MEMORANDUM

TO: Robert J. Taggart

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SUBJECT: Application for Permits to Construct a Refinery Pollution Control Upgrade Project (PCUP) at the Premcor Refining Group, Inc.'s Delaware City Refinery

DATE: September 15, 2004

Background:

The Premcor Refining Group, Inc. (Premcor) owns and operates the Delaware City Refinery located at 2000 Wrangle Hill Road in Delaware City, Delaware. Premcor assumed ownership of the Delaware City Refinery effective May 1, 2004. Prior to May 1, 2004, this refinery was owned by Motiva Enterprises, LLC a joint venture between Shell Oil products US and Saudi Aramco. Two landmark settlement agreements were executed in 2001 for past violations that occurred at the Delaware City Refinery. The settlement agreements are documented in two separate civil actions:

- a federal civil action involving nine Alliance Company petroleum refineries located in five different states, the United States Environmental Protection Agency, the United States Department of Justice, the States of California, Delaware, Louisiana, Texas and Washington;[1] and

- a state specific civil action that focused only on the Delaware City Refinery.[2]

An integral part of these settlement agreements required Motiva and its successors to install pollution control equipment in several major processes to control criteria pollutant and hazardous air pollutant (HAP) emissions.

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[1] There were 2 separate federal actions: 1. Civil Action H-01-0978 (for the Heaters and Boilers Marquee Issue) dated March 21, 2001 between the United States of America, Plaintiff and the States of Delaware, Louisiana and the Northwest Air Pollution Authority of the State of Washington, Plaintiff-Interveners versus Motiva Enterprises LLC, Equilon Enterprises, LLC and Deer Park refining Limited Partnership, Defendants entered in the United States District Court for the Southern District of Texas.

[2] Civil Action 18750 NC dated March 22, 2001 between Nicholas A. DiPasquale, Secretary of the Department of Natural Resources and Environmental Control, an agency of the State of Delaware, Plaintiff versus Motiva Enterprises LLC, Defendant entered in the Court of Chancery of the State of Delaware in and for New Castle County.

Motiva Enterprises, LLC submitted applications on March 29, 2004 for the construction of the following pollution control equipment and improvement projects collectively termed as the Delaware City Refinery Pollution Control Upgrade Project (PCUP):

- A Belco Technologies prescrubber, a Cansolv amine based regenerative wet gas scrubber and a polishing scrubber to treat sulfur oxide emissions in the exhaust gas from the fluid coking unit's carbon monoxide boiler.
- A GE Energy and Environmental Research Corporation selective non catalytic reduction system to reduce nitrogen oxide emissions in the exhaust gas from the fluid coking unit's carbon monoxide boiler.
- A Belco Technologies prescrubber, a Cansolv amine based regenerative wet gas scrubber and a polishing scrubber to treat sulfur oxide emissions in the exhaust gas from the fluid catalytic cracking unit's carbon monoxide boiler.
- Installation of piping to route the slurry recycle from the fluid catalytic cracking unit to the fluid coking unit's reactor scrubber.
- Two package boilers (each with a design rated heat input of 216 mmBtu/hour) to supply steam for the regeneration of the amine–based sorbent used in the regenerative wet gas scrubbers.
- Modification of the sulfur recovery area to reroute the ammonia from the pre-combustor of the crude unit atmospheric heater and to allow the processing of the recovered sulfur dioxide from the wet gas scrubbers.
- Concurrent other changes to allow incremental improvements in refinery operations.

The basis for the PCUP related constructions and modifications are found in the Second Addendum to Civil Action H-01-0978 between the United States of America (Plaintiff) and the States of Delaware and Louisiana (Plaintiff-Interveners) versus Motiva Enterprises LLC (Defendant), entered on December 24, 2003 in the United States District Court for the Southern District of Texas and in Civil Action No. 18750 NC between Nicholas A. DiPasquale, Secretary of the Department of Natural Resources and Environmental Control, an Agency of the State of Delaware (Plaintiff) versus Motiva Enterprises LLC (Defendant), entered on March 22, 2001. In accordance with paragraph 168a of the Second Addendum, Motiva was required to submit complete applications by no later than March 31, 2004 for all state and federally enforceable permits necessary for the installation of regenerative WGS systems on the DE City FCU and FCCU and other contemporaneous or related projects. The Department has to issue its decision on all state and federally enforceable permits related to the FCU as contained in those permit applications received on or before March 31, 2004, within 8 months of receipt of Motiva's application. The Department has to issue its decision on the remaining state and federally enforceable permits as contained in those permit applications, received on or before March 31, 2004 within 14 months of receipt of Motiva's application. Motiva's applications were received

by the Department on March 29, 2004. Therefore AQM has identified the following unit operations as requiring permits by no later than November 30, 2004:

- Fluid coking unit (FCU)
- FCU wet gas scrubber (WGS)
- FCU SNCR
- Two new package boilers
- SRA modifications
- Crude unit modifications
- Crude unit atmospheric heater modificationss

The following unit operations will require permits by no later than May 31, 2005 (i.e., the 14 month deadline):

- The fluid catalytic cracking unit (FCCU)
- The FCCU WGS
- Coke handling and storage area modifications

This memorandum consists of the following 3 parts:

- Part 1: Project description for the FCU and FCU related projects;
- Part 2: Regulatory and technical analysis of each affected units/process whose permits have to meet the November 30, 2004 deadline; and
- Part 3: Draft permits for the affected units, i.e. the FCU and FCU related projects.

Glossary of Terms:

AQM: DNREC's Air Quality Management
BACT: Best Available Control Technology
BPD: Barrels per day
COB: Carbon monoxide (CO) boiler
DCR: Delaware City Refinery
ESP: Electrostatic Precipitator
ESPC: Equivalent Sulfur Plant capacity
FCCU: Fluid Catalytic Cracking Unit
FCU: Fluid Coking Unit
LAER: Lowest Achievable Emission Rate
LTPD: Long tons per day
MACT: Maximum Achievable Control Technology

NESHAP: National Emission Standards for Hazardous Air Pollutants
NSPS: New Source Performance Standards
NSR: New Source Review
PCUP: Pollution Control Upgrade Project
RACT: Reasonably Available Control Technology
RFG: Refinery fuel gas
SCR: Selective catalytic reduction
SRA: Sulfur Recovery Area
SNCR: Selective non-catalytic reduction
TPY: Tons per year, as determined on a twelve month rolling total
WGS: Wet Gas Scrubber

Part 1: Project Description

This part of the memorandum describes the project description as it relates to existing operations and the proposed changes. As a result of the Delaware City Refinery Pollution Control Upgrade Project (PCUP) new emissions controls will be installed for certain existing unit operations. In addition, several existing unit operations will be modified as part of the project. Overall, the PCUP will impact the following unit operations:

- crude unit
- crude unit atmospheric heater (21-H-701)
- fluid coking unit (FCU)
- FCU carbon monoxide boiler (COB)
- Fluid catalytic cracking unit (FCCU)[3]
- FCCU COB[3]
- sulfur recovery area
- gas fired boilers
- coke handling and storage operations

Crude Unit (Unit 21):

Existing operations of the crude unit constructed in 1956 is comprised of the following processes:

- Desalters: There are no direct emissions from the desalters.
- Sour water stripping plant: There are no direct emissions from the sour water stripping plant. Ammonia waste stripped from the sour water in 21-C-303 is routed to the precombustor unit of 21-H-701 where it is destroyed.
- Atmospheric heater 21-H-701[4], and the atmospheric distillation tower: Emissions from 21-H-701 are vented through emission point 21-1. There are no direct emissions from the atmospheric tower.
- Vacuum heater 21-H-2 and the vacuum distillation tower: Emissions from 21-H-2 are vented through emission point 21-1. There are no direct emissions from the vacuum tower.
- Merox treatment unit: Spent Merox air is vented to the firebox of unit 21-H-701 or to unit 28-S-202 in the SRA.

[3] The permit for the FCCU and the FCCU COB will be processed separately to meet the 14 month deadline in accordance with the provisions of paragraph 168a of the Second Addendum to the CD.

[4] The atmospheric heater unit 21-H-701 was constructed in 1996 as a replacement to the old 21-H-1 unit which is decommissioned.

Process Description:

The crude unit is the first important unit operation in the refinery. This operation includes heating, vaporization, fractionation, condensation and cooling, thereby separating incoming crude oil into various boiling fractions. The crude unit accomplishes the distillation in two stages - the total crude is fractionated in an atmospheric tower and the high boiling bottoms are further fractionated in a vacuum tower. The incoming crude is desalted and heated to 650 EF in the atmospheric heater unit (21-H-701). The crude flows to the main fractionator where various boiling fractions are separated. The atmospheric tower bottoms are heated in the vacuum tower heater (21-H-2) and further fractionated in the vacuum tower. Desalted effluent water is stripped and the overhead is routed to the sour water stripping plant where acid gas (H_2S and NH_3) are removed. The H_2S is fed to the sulfur plant for sulfur recovery and the NH_3 is routed to the precombustor unit of 21-H-701.

Unit 21-H-701 consists of 2 main units: a) A pre-combustor that is fired by refinery fuel gas with the objective of destroying a design load of 975 SCFM NH_3 from the sour water stripper; and b) the process heater fired by refinery fuel gas designed to heat the incoming crude oil to about 400 EC prior to feeding the crude stock to the main atmospheric distillation column. The process heater is vertically fired and has a horizontal tube radiant section in two separate furnace cells. There is a convection section and steam superheat coil at the top of the heater that is common to both furnace cells. There are two flue uptakes from the process heater leading to a stack shared with the Vacuum Heater Unit 21-H-2. The two heater units also presently share common NO_x and CO_2 analyzers. Both units fire either natural gas or desulfurized RFG[5]. There are 8 burners per side. Finally, because gasoline produced in the crude unit has a high sulfur content in the form of mercaptans and thiols, it must be sweetened.

The light straight run (LSR) gasoline from the atmospheric tower and the coker gasoline containing similar sulfurous impurities are sweetened in a portion of the crude unit called the Merox treater. This is essentially an oxidation process where thiol sulfur is converted to a disulfide. This is done by contacting the sour gasoline with a caustic solution containing the Merox catalyst to extract the mercaptans. The extracted gasoline is sweetened by reacting it with air in the presence of Merox-containing caustic solution. Spent merox air is routed to the furnace of unit 21-H-701 or to the sulfur plant as an alternate control device. The sour water generated by the crude desalting process is led to tankage in Tank 471. From tank 471, sour water is stripped in the sour water stripper. Stripped H_2S is led to the sulfur plant for sulfur recovery. The

[5] Unit 21-H-2 used to have the ability to combust No. 6 oil. However, this practice was discontinued effective October 31, 2003 pursuant to a requirement in the federal CD.

stripper accumulator overhead condenser is cooled by river water and controls the amount of H_2S that is carried over with the ammonia waste stream to the precombustor.

Planned Changes to the Crude Unit:

The planned changes to the crude unit include the following:

- Design throughput will increase from 183,000 BPD to 185,142 BPD[6].
- The withdrawal point for the light virgin gas oil (LVGO) draw from the crude unit atmospheric tower will be raised.
- The pre-combustor (21-H-703) and the selective non-catalytic reduction system (SNCR)of the atmospheric process heater (21-H-701) will be decommissioned. 21-H-703 and the SNCR system presently serve as the control device to destroy the ammonia waste stream from the sour water stripper. As part of the PCUP, this ammonia stream will be rerouted to the sulfur recovery area. The combustion of the ammonia waste stream in 21-H-703 provides about 15 mmBtu/hour of sensible heat input to the atmospheric heater because the flue gas from 21-H-703 exhausts into the firebox of 21-H-701. The lost heat input resulting from decommissioning 21-H-703 and the SNCR system will be made up by installing a new 15 mmBtu/hour low NO_x burner in the firebox of 21-H-701.

Fluid Coking Unit (FCU, Unit 22):

The fluid coking unit (FCU) converts refinery intermediates, purchased feedstocks and other materials into gasoline and other intermediate products. The FCU is comprised of the following units/processes:

! FCU reactor, scrubber and burner and start up air heater (22-H-1) with a rated design heat input of 107 mmBtu/hour.
! FCU Selas steam superheater (22-H-2) with a rated design heat input of 17.8 mmBtu/hour.
! FCU carbon monoxide boiler (COB, Unit 22-H-3) with a rated design heat input of 674.7 mmBtu/hour and its electrostatic precipitator (ESP)
! FCU back up incinerator (22-H-4) with a rated design heat input of 942 mmBtu/hour
! Coke storage and handling facility

[6] Although the application indicates the crude unit has a design existing capacity of 183,000 BPD, because of capacity limitations of downstream processing units, the effective design throughput of the crude unit is 175 MBPD.

Process Description:

The FCU allows the refinery to process low cost, high sulfur crude oil to produce high value products such as gasoline, thereby increasing profitability. Vacuum residuum from the vacuum distillation tower of the Crude Unit is the main feedstock to the FCU. This feed enters the scrubber section of the FCU where it is blended with cooled recycle oil. Recycle oil is blended oil at the bottom of the scrubber that has been used to scrub out coke particulate matter. About 66 % of this combined recycled scrubber oil is fed to the reactor through three inlet distribution rings having a total of 42 feed injection nozzles. The feed thus comes into contact with hot coke in the reactor (about 980EF) and breaks up into smaller chains of hydrocarbons by the process of thermal cracking. The coke bed is kept in a fluidized state by injection of fluidizing steam at 175 psig and 750E F through 37 steam nozzles. Cold coke at about 950EF is drawn from the bottom of the reactor and returned to the burner where combustion air is supplied to burn the coke partially and generate the heat necessary to sustain the endothermic cracking reaction in the reactor. The hot coke is withdrawn through an overflow well and is fed to the reactor to continue the cracking operation. Excess product coke is withdrawn through a quench elutriator prior to its being conveyed by conveyor belts to a storage area on site north of the powerhouse. About 2000 TPD(daily average) or 1,880 TPD (annual average) of product coke leaves the elutriator at 425EF.

Scrubber overhead at a rate of 350 tons per hour is fed to the bottom of the main Fractionator (Column C-1). Light gas oil from C-1 is condensed and refluxed with additional gasoil from Tray No. 7 and fed to the Hydrocracker or the Fluid Catalytic Cracking Unit (FCCU) as feed. C-1 bottoms are refluxed to the top of the scrubber. C-1 overheads flow to a flash drum and accumulator which allows the separation of gas, fractionator overhead liquid and water. About 200 tons per hour of wet gas is produced. Coker gasoline is extracted from the accumulator and split into fractionator reflux and excess going to the flash drum. The latter is heated and flashed with the vapors being condensed and sent to the absorber/stripper column where the liquid is extracted and pumped to storage for use as feed to the FCCU.

The burner unit contains about 350 tons of coke. The circulation of this coke through the reactor and back to the burner is controlled by two slide valves that achieve precise control. The stoichiometry for the combustion process in the burner unit is as follows:

$$2\ C + O_2 \equiv 2\ CO;\ )H = -\ 110.5\ kJ/mol$$

During periods of start up, an air heater (Unit 22-H-1) rated at 107 mmBtu/hour is used to supply the heat necessary to initiate the combustion stoichiometry given above. This unit fires only refinery fuel gas and is supplied by a forced draft fan.

In order to keep the coke fluffed, an auxiliary refinery fuel gas fired steam superheater called the Selas Steam Superheater (Unit 22-H-2) is provided. This unit is fired continuously and provides 175 psig steam that is injected at strategic points with the aid of special steam injection nozzles. Unit 22-H-2 is rated at 17.8 mmBtu/hour.

The CO formed leaves the burner through 18 two-stage cyclones and flows to one of two water seals before entering the CO boiler. During periods when the CO boiler and/or the ESP unit have to be taken off line, flue gases can be processed in the Back Up Incinerator Unit (Unit 22-H-4). The system is designed so that during periods when the CO Boiler and/or the ESP is down, the affected unit can be by-passed and the gases routed to the Back Up Incinerator. However, because of the possibility of high temperature damage to the electrodes in the ESP, plant operators prefer to always bypass the ESP together with the CO Boiler whenever the latter unit (the CO Boiler) has to be taken off line.

Planned Changes to the FCU:

The planned changes that affect the FCU include the following:

- Installation of an amine-based regenerative wet gas scrubber (WGS) system and upgrades to the COB to accommodate the WGS installation. This is the primary change planned at the FCU for compliance with the injunctive relief measure prescribed in the CD. The WGS system will include a water pre-scrubber, an amine-based regenerative scrubber and a caustic polisher along with ancillary equipment needed to support the scrubber (i.e., the regeneration system, air coolers, gas fired package boilers etc). The WGS will replace both the existing ESP and the COB exhaust stack with an integrated scrubber stack system that is designed to remove particulate matter, sulfur dioxide and sulfur trioxide from the FCU flue gas.

  There are 2 main elements in the WGS – the scrubber and regeneration systems. The scrubber element consists of a Belco prescrubber followed by a Cansolv absorber section. The purpose of the Belco prescrubber is to saturate the flue gas with water and to remove particulate matter and sulfur trioxide before the gas enters the absorber section. The main SO_2 absorption section of the Belco/Cansolv WGS uses an amine-based scrubber solution in a packed bed absorber tower to remove SO_2 from the exhaust stream. The main absorption loop is followed by a polishing scrubber, which is a final packed stage that is separate from the amine-based absorption step and will be used to ensure that the CD driven levels of control are achieved (i.e., 25 ppmvd @ 0 % O_2 on a 365 day rolling average basis and 50 ppmvd @ 0 % O_2 on a 7 day rolling average basis).

The Belco prescrubber section consists of a quench section followed by Agglofilter modules and Cyclolab droplet separators. A low pH is maintained in the prescrubber section to maximize the SO_2 absorption in the absorber section. The quench and Agglofilter modules remove particulate matter and SO_3 while the Cyclolabs remove any large entrained droplets carried over from the prescrubber. Blowdown from the prescrubber flows to a purge treatment unit where it is neutralized with caustic and clarified prior to being routed to the refinery's effluent treatment plant.

A packed tower serves as the absorber where the gas is contacted with an amine which absorbs the SO_2. Cleaned gas will exit the absorber through a stack mounted on the absorber tower.

Rich amine is filtered and heated through an effluent-influent heat exchanger before being fed to the regenerator tower. In the regenerator, the rich amine is steam stripped yielding a high purity SO_2 stream that will be routed to the refinery's SRA. The regenerated lean amine is pumped back to the absorber. Because heat stable salts (HSS) are formed over time, a small slip stream of lean amine is routed to an electro-dialysis unit to extract the HSS from the lean amine.

Process Chemistry[7]:

In an aqueous solution, SO_2 undergoes reversible hydration and ionization according to the following equations:

$SO_2 + H_2O \leftrightarrow H^+ + HSO_3^-$ ……..Eq. 1

$HSO_3^- \leftrightarrow H^+ + SO_3^=$ ……Eq. 2

Equations 1 and 2 are half completed at pH values of 1.81 and 6.91 respectively at 18 deg. C. To increase the quantity of SO_2 dissolved in the water an amine buffer is added driving the above equilibria to the right by reacting with the hydrogen ions to from ammonium salts:

[7] AQM's research has found the most concise description of the process chemistry in a technical paper titled "Refinery and Natural Gas Applications of Cansolv System Technology" authored by Paul J. Parisi and John C. Bourdon, presented at "Sulphur 97", November 18, 1997 in Vienna. This excerpt is a section from the above referenced paper.

$R_1R_2R_3N + H^+ \leftrightarrow R_1R_2R_3NH^+$ ……..Eq. 3

In order for the process to be regenerable, the buffering agent should operate in a pH region sufficiently low so as to present a desirable value of SO_2 vapor pressure over the solution at the regeneration temperature. Steam stripping the vapor phase SO_2 will reverse Equations 1 ~ 3 thus regenerating the amine absorbent.

The Cansolv system process is based on a class of diamine absorbents that optimally balance the ability to absorb and regenerate SO_2. One of the amine functionalities of the absorbent is strongly basic that it is not thermally regenerable under the Cansolv system process conditions. So, once reacted into a salt by SO_2 or any stronger acid, this strongly basic amine functionality will remain permanently as a salt.

$R_1R_2N\text{-}R_3N\text{-}NR_4R_5 + HX \leftrightarrow R_1R_2NH^+\text{-}R_3\text{-}NR_4R_5 + X^-$ ……..Eq. 4

The monoprotonated amine on the right hand side of Eq. 4 is the in-process lean amine which is used to scrub the SO_2. This is a HSS.

The second amine functionality (the "sorbing nitrogen") is less basic and it buffers in the desired range for regenerability of SO_2, which in practice is about pH 4 for the rich amine and pH 6 for the lean. This buffering range provides the proper balance of absorption and regenerability as shown in Eq 5 below:

$R_1R_2NH^+\text{-}R_3\text{-}NR_4R_5 + SO_2 + H_2O \leftrightarrow R_1R_2NH^+\text{-}R_3\text{-}NH^+R_4R_5 + HSO_3^-$ … .Eq. 5

In Eq 5 the anion X^- is not shown as it does not participate in the SO_2 reaction with the sorbing nitrogen. The nature of X^- can affect the functioning of the process: if it is SO_3^{2-} it can contribute to SO_2 scrubbing. However, if X^- is the anion of a strong acid and is allowed to accumulate more than 1 equivalent per mole of amine, it will neutralize the sorbing nitrogen and thereby decrease the scrubbing capacity of the solvent. Thus the level of the HSS is kept below 1 equivalent per mole of solvent by purging a slip stream to an electro-dialysis purification unit which replaces the non-regenerable sulfate anions by sulfite or bisulfite ions.

- Decommissioning the ESP.

- Installation of an ammonia based selective non-catalytic reduction (SNCR) system on the FCU COB. The SNCR process involves injection of a reagent such as ammonia or urea into the COB combustion gases. When the desired temperature and residence time is

maintained the reagent will selectively react with the nitric oxide to reduce it to molecular nitrogen. Although the optimium temperature depends on the reagent and furnace thermal characteristics, the accepted window for SNCR applicability is generally in the range of 1,600 deg F to 2,100 deg F. GE Energy Services has developed a design based on computational fluid dynamics (CFD) to inject aqueous ammonia into strategic locations within the COB. GE has provided the following performance guarantees:

- NO_x emissions of less than or equal to 78 ppmvd @ 3 % O_2 based on a 40 % removal efficency measured from the baseline model of 130 ppmvd @ 3 % O_2

- NH_3 emissions of less than or equal to 20 ppmvd @ 3 % O_2

The SNCR system will include two 28,000 gallon ammonia storage tanks for storing 19.5 % aqueous ammonia. The aqueous ammonia is transferred from the storage tank to the SNCR process using a pump skid. An ammonia flow control unit (AFCU) is required in this system to regulate the ammonia flow to the SNCR system. The AFCU consists of the following components:

- Dilution air supply unit which uses one of two centrifugal air blowers to supply the dilution air. The blower discharge will be split into two streams – injection air and dilution air. Injection air is sent to the distribution air skids to be combined with the vaporized ammonia streams. Dilution air is sent to the AFCU.
- Liquid ammonia supply line with flow control valve and automated shut off valve
- Instrument air line and pressure control valve
- Dilution air steam header
- Vaporizer which is packed with pall rings to increase the surface area for ammonia vaporization. When the aqueous ammonia is injected into the vaporizer, it will be evaporated as it mixes with the heated dilution air.
- Superheated steam supply to heat the dilution air using finned coils enclosed in a sheet metal duct assembly
- PLC panel and instrumentation

The SNCR system will contain 14 injector nozzles. Six of these nozzles will serve as front wall injectors. The nozzles will be arranged in pairs with the higher velocity nozzles being located at a higher elevation. All front wall nozzles will be angled down at 30 degrees with the bottom row of injectors also yawed towards the left wall by 30 degrees. The remaining 8 nozzles will serve as side wall injectors through two tube wall penetrations on opposite side walls. Each set of nozzles will be individually fed and equipped with hand valves for field adjustment of individual injection zones to assure optimum reagent coverage.

- Installation of piping to route the slurry recycle from the fluid catalytic cracking unit (FCCU) riser to the FCU reactor scrubber. Physically, this modification involves installing a jumper downstream of the reslurry control valve to downstream of the decant oil cooler. From an operational standpoint, this change is expected to reduce the FCCU stack opacity and reduce FCCU HAP emissions.

- Installation of redesigned jet trays in the FCU reactor scrubber. The current jet trays in the FCU scrubber have a tendency to flood. New trays designed to eliminate this tendency will be installed.

- Redesign of the product coke withdrawal system. The PCUP is expected to result in an increase in coke production of about 550 TPD from the FCU. Because the existing coke product withdrawal system has caused operational problems, Premcor plans to redesign the product coke withdrawal system. The new design involves increasing the size of the coke product lines and installing parallel lines to facilitate repairs.

- Installation of jumpers to use heat exchangers 22-E-18 and 22-E-318 in heavy gas oil pumparound service and installation of jumpers to allow back flushing the 22-E-2 A/B strainers to the heavy pumpout system

- Upgrade of the COB and emergency incinerator combustion controls and/or equipment

Fluid Catalytic Cracking Unit (FCCU, Unit 23):

The permit for the FCCU and the FCCU COB will be processed separately to meet the 14 month deadline in accordance with the provisions of paragraph 168a of the Second Addendum to the CD.

Sulfur Recovery Area (SRA, Unit 28):

The SRA, constructed originally in 1956 and modified last in 1996, is comprised of the following processes:

! Two (2) Claus units - SRU -I (formerly referred to as SRU -III) with an equivalent sulfur plant capacity (ESPC) of 250 LTPD and SRU - II. with an ESPC of 350 LTPD Because the Claus units vent to either of the Shell Claus Offgas Treatment (SCOT) units, there are no direct emission points from the Claus units to the atmosphere.
! Two (2) SCOT units. SCOT unit emissions are vented to the atmosphere through Emission Point 28-1A and 28-1B.

Process Description:

Acid gas from the refinery's existing amine scrubbing systems and sour water strippers are fed to the SRUs to recover elemental sulfur. The primary constituent of the acid gas is Hydrogen sulfide (H_2S) at a concentration of 85 % to 92%. The refinery utilizes the Claus process which consists of two basic steps. First, a portion of the H_2S is converted to Sulfur dioxide (SO_2) by combustion. Second, the remaining H_2S reacts with the newly formed SO_2 to produce elemental sulfur. These reactions are given by the following equations:

$$2\ H_2S\ +\ 3\ O_2\ \equiv 2\ SO_2 +\ 2\ H_2O \quad \text{..... Equation 1}$$

$$4\ H_2S +\ 2\ SO_2\ \equiv 6\ S\ \ +\ 4\ H_2O \quad \text{..... Equation 2}$$

Summing the 2 equations:

$$6\ H_2S\ +\ 3\ O_2\ \equiv 6\ S\ \ +\ 6\ \ H_2O$$

The Claus process employs both thermal and catalytic reactors to accomplish the reactions shown in Equations 1 and 2 above with the ideal molar ratio of H_2S:SO_2 = 2.0. The reaction is carried out to completion in a thermal reactor and a series of catalytic reactors. About 60 percent of the feed sulfur is recovered in the thermal reactor and the rest is recovered in the catalytic reactors to give an overall sulfur recovery in the range of 95% to 96 % in the Claus units. The hot gases from the reaction furnace are cooled in a waste heat exchanger and in the sulfur condensers producing both 600 psig and 50 psig process steam for use in the refinery. The sulfur vapor is removed by condensation providing reactant equilibrium that favors furthering the reaction to the right and producing more sulfur in the catalytic converter stages that follow.

Remaining sulfur in the tail gas is fed to the SCOT units[8]. The Claus tail gas essentially consists of H_2S, SO_2 Carbonyl sulfide (COS), Carbon disulfide (CS_2) and trace amounts of elemental sulfur. All of these sulfur forms are reduced to H_2S in the presence of hydrogen. The H_2S is then selectively absorbed in Methyl diethanol amine (MDEA) solvent, which in turn is stripped. The stripped H_2S is recycled to the Claus Units and the SCOT tail gases are incinerated where trace H_2S is oxidized to SO_2 in a waste gas incinerator prior to discharge from a dedicated stack. The New Source Performance Standard for the SO_2 emissions from this stack is 250 ppm at zero % oxygen on a rolling twelve hour average and dry basis. The condensed sulfur is collected in

[8] Tailgases from the SRUs are processed as follows: SRU I ≡ SCOT II and SRU II ≡ SCOT I

sulfur pits and transferred to holding tanks from where it is loaded into railcars and shipped off site.

Emissions from both these points include criteria pollutants from combustion of refinery fuel gas in the SCOT incinerators[9]. The NSPS emission limit for SO_2 is 250 ppm at 0 % oxygen on a rolling twelve hour average and dry basis.

Planned Changes to the SRA:

The planned changes that affect the SRA include the following

- Revisions to the feed piping, control systems and safeguarding systems
- Addition of two new feed streams, i.e., the sour water stripper ammonia off gas and the sulfur dioxide from the WGS systems
- Installation of a knock out drums[10]
- Installation of a new air cooler bay for lean amine
- Modifications to the outlet of the waste heat boiler, outlet piping and inlet of the 1st sulfur condenser
- Upgrade of a portion of the 1st Claus catalytic reactor catalyst to increase COS and CS_2 hydrolysis
- Modifications to the 1st Claus catalytic reactor outlet piping and inlet of the 2nd sulfur condenser
- Changes to the catalyst used in the tail gas treating (SCOT) unit hydrolysis process to increase COS hydrolysis
- Modifications to the SCOT reboilers
- Installation of new oxygen burners to allow up to 60 % oxygen enrichment
- Installation of a new air cooler bay for quench water
- Modifications to the SCOT absorber and regenerator internals
- Change of SCOT solvent to improve H_2S absorption and CO_2 slip
- Replacement of the existing oxygen piping and skids
- Other minor process and/or equipment changes that may be needed to accommodate the estimated increased processing rates.

As a result of these changes the SRA capacity will increase to 822 LTPD.

[9] Unlike SCOT II, SCOT I is equipped with a waste heat boiler 28-H-201
[10] The installation of knock out drums was permitted in April 2003

Package Boilers A and B:

Each package boiler has a heat input rating of 216 mmBTU/hr and will be powered by refinery fuel gas. They will be used to supply all the steam for the regeneration of the amine-based sorbent used in the wet gas scrubber systems, approximately 150,000 pounds per hour of steam, each. Premcor has not provided a steam balance for the plant.

Part 2: Regulatory and Technical Analysis

This section evaluates the regulatory and technical considerations for all emission units affected by the PCUP. In each case the applicable regulation or requirement is stated followed by descriptions of the compliance methodology, monitoring/testing, recordkeeping and reporting requirements.

As explained in the background section of this memorandum, Paragraph 168a of the second addendum to the consent decree provided for the review of the PCUP application in 2 phases, i.e., within 8 months of receipt of the permit applications for FCU and FCU related projects and within 14 months of receipt of the applications for all other projects. Therefore, one of the first steps taken by the Department in its review was to identify the scope of the work that would fall in Phase 1. To this end, Premcor provided AQM with the following unit operations as requiring permits within the 8 month timeframe:

- Crude unit
- Crude unit atmospheric heater (21-H-701)
- FCU and it's wet gas scrubber
- FCU COB and the SNCR system
- SRA modifications
- Installation of package boilers
- Modification of the coke handling and storage facility to handle the increased coke production

Table 1 provides a summary of the net emissions changes that will result from the implementation of the PCUP. In this netting transaction, the emissions comparison includes only the units that fall under Phase 1 of the PCUP permitting exercise. A similar emissions comparison and evaluation will be conducted for the Phase 2 of the PCUP (14 month permitting items).

Table 1: PCUP Phase 1 Expected Emissions Changes

	Baseline Emissions					Potential to Emit						Projected Δ	
Pollutant	CU	FCU	FCCU[11]	SRA[12]	Total	CU	FCU	FCCU	SRA	PB	Total	Rest of Refinery[13]	Net Change[14]
SO_2	23.4	19215	TBD	156.5	29073	48.1	173.8	TBD	672.1	42.3	1297	1	-18458.7
NO_x	73.8	689.8	TBD	30.7	794.3	92.3	457	TBD	51.9	13.2	614.4	1.2	-178.7
TSP	18.6	276.6	TBD	6.1	301.3	42	206.3	TBD	22.3	12.1	282.7	TBD	-18.6
H_2SO_4	0.4	268.8	TBD	5.9	275.1	0.7	252.2	TBD	11.6	0.8	265.3	0	-9.8
PM_{10}	19	545.4	TBD	6.1	570.5	42.9	458.5	TBD	10.8	12.9	525.1	TBD	-45.4
CO	0	1296.3	TBD	7.7	1304	75.1	416	TBD	26	133.9	651	0.9	-652.1
VOC	0.9	103.5	TBD	0.7	105.1	6.4	43.8	TBD	1.3	8.8	60.3	1.0	-44.8
Pb	7.3 E-4	6.9 E-2	TBD	1.1 E-4	7.0 E-2	9.1 E-4	9.0 E-2	TBD	1.8 E-4	8 E-4	9.0 E-2	0	2.0 E-2
TRS/RSC	0	5.8 E-3	TBD	7	7	0	7.8 E-3	TBD	12.7	0	12.7	0	5.7
H_2S	0	5.8 E-3	TBD	7	7	0	7.8 E-3	TBD	12.7	0	12.7	0	5.7

[11] The Department has not approved Premcor's use of October 1, 2002 through December 31, 2003 as being a representative baseline period for the FCCU. Hence, FCCU baseline emissions are yet to be determined (TBD).

[12] For the SRA, Premcor has used the "current allowable" emissions as the baseline emissions. On the other hand, AQM has used the 12 month period of July 2003 through June 2004 to compare "current actual" emissions to the "future potential" emissions.

[13] Emissions changes shown under "Rest of Refinery" include the emissions changes associated with unmodified process heaters and unmodified process units. Emissions from these unmodified sources are expected to change because of the projected units' utilization changes. Emissions changes associated with the unmodified process heaters were based on the Delaware City Refinery Linear Program model's predicted changes in the average daily heat input to the various combustion units. The estimated change in average heat input was multiplied by the current emissions factor for each unit's heaters and converted to a TPY basis. Emissions changes from unmodified process operations were calculated as the difference between the emissions from these units when the crude throughput is 185 MBPD (i.e, the post PCUP operating scenario) and the baseline crude throughput of 165MBPD. TSP and PM_{10} emissions changes are yet to be determined because the application does not include an AQM 4 application form for the modifications to the coke handling and storage facility.

[14] The net change in emissions are the estimated changes after Phase I of the PCUP.

Crude Unit (Unit 21):

Regulation No. 2 - Permits:
Section 2.1 (c) of this Regulation states:
Except as exempted in Section 2.2, no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department or, if eligible, prior to submitting to the Department a completed registration form for equipment, a facility or an air contaminant control device that is not subject to Section 2.1(a) or 2.1(b), the person shall submit to the Department an application for a permit pursuant to Section 11of this regulation.

Section 11.6 of this Regulation states:
No permit shall be issued by the Department unless the applicant shows to the satisfaction of the Department that the equipment, facility, or air contaminant control device is designed to operate or is operating without causing a violation of the State Implementation Plan, or any rule or regulation of the Department, and without interfering with the attainment or maintenance of National and State ambient air quality standards, and without endangering the health, safety, and welfare of the people of the State of Delaware. The Department may, from time to time, issue or accept criteria for the guidance of applicants indicating the technical specifications which it deems will comply with the performance standards referenced herein.

Furthermore, Section 11.8 states:
The following emission rates and/or standards for each air contaminant emitted from any equipment, facility or air contaminant control device shall be specified in each permit issued pursuant to this regulation:

*a. The rate and/or standard established and/or relied upon in the State Implementation Plan (SIP) to include the State of Delaware "**Regulations Governing the Control of Air Pollution**" and regulations promulgated pursuant to Section 111 and Section 112 of the Clean Air Act (CAA); and*

b. The rate that was shown under Section 11.6 as not interfering with the attainment and maintenance of any National and State ambient air quality standard, and not endangering the health, safety, and welfare of the people of the State of Delaware; or

c. The rate requested by the applicant. In no case shall this rate be greater than the potential to emit of the equipment, facility, or air contaminant control device; and in no case shall this rate be less stringent than the rate specified in Section 11.8(a) and (b) of this regulation.

This regulation is applicable to the crude unit since changes involve alteration of equipment that emits air contaminants.

The crude unit was constructed in 1956 with a design throughput capacity of 130,000 BPD. Over the following years numerous process operating changes have increased the throughput capacity of the crude unit to its present capacity of 185 MBPD. The Company has indicated that despite its present capacity of 185,000 BPD, bottlenecks posed by downstream equipment restrict the actual throughput capacity to 175 MBPD.[15] The crude unit is the unit operation that is the first step in the refining process of converting crude oil into usable product as shown in Figure 1. It does this by separating constituents of the incoming crude oil into various boiling point fractions that are processed in downstream units. Thus any increases or decreases in the crude unit's throughput will result in consequent increases or decreases in throughputs of downstream units. All emissions from the refinery are thus dependant on the feed throughput through the crude unit. As a result of the PCUP the Delaware City Refinery will be able to increase its crude throughput from the baseline actual of 165 MBPD to 185 MBPD[16]. In fact, Premcor's application recognizes this concept and calculates emissions changes from downstream units based on the projected change in throughput as shown in Table E-13 of the PCUP application. This increase becomes possible because of two main factors. First, the existing restriction of 4,450 lb/hour SO_2 emissions from the downstream FCU will no longer be a bottleneck after the WGS is installed to control SO_2 emissions, and second, the existing sulfur recovery area (SRA) capacity will be increased from 556 LTPD to 822 LTPD. These two units, i.e., the FCU and the SRA, together with the FCCU and the coke handling facility are unit operations that are directly affected by the PCUP, and are therefore subject to review under this permitting effort as a result of which new enforceable emissions limitations will be established. However, the remaining units in the refinery, although undergoing no physical changes as part of the PCUP, will also be affected units because of the impacts of the increased throughput of the crude unit. Compliance with emission limits for these other units are often based on fuel usage and stack test derived emissions factors. Performance tests should therefore be conducted during a period of operation that constitutes a "worst case scenario" for air emissions. The permit usually defines a maximum firing/process rate which constitutes the "worst case scenario." Under 40 CFR 60.8 Section (c) "Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests." The completion of a stack test program

[15] The crude unit at the Delaware City refinery has a nominal throughput of 165,000 BPD which is representative of normal operations. Although, the crude unit can run at a higher throughput, it is effectively limited at 175,000 BPD because of the existing restrictions on the operation of the fluid coking unit and capacities of the sulfur recovery area and the hydrogen plant.
[16] Section E.7.5 of Premcor's PCUP application dated March 29, 2004, describing Other DCR Process Unit Emissions Changes.

ensures compliance at a certain firing/process rate and will not be representative of emissions at higher firing/process rates.

Because of the reasons described above, AQM finds it appropriate to incorporate a throughput restriction in the crude unit permit. Furthermore, because Section 11.8 (c) prohibits limit greater than the potential to emit[17] of the equipment, AQM is establishing the throughput restriction at the maximum daily level of 185,142 barrels.

Compliance Methodology:

The draft permit will include the following condition:

The crude unit throughput shall not exceed 185,142 barrels per day.

Monitoring/Testing:

The Company shall monitor the daily throughput to the crude unit

Recordkeeping:

The Company shall maintain records of the daily throughput

Reporting:

The Company shall submit quarterly reports due by the end of the first month following each quarter indicating each day the throughput exceeds 185,142 barrels per day and the magnitude of each exceedance.

[17] "Potential to Emit " means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

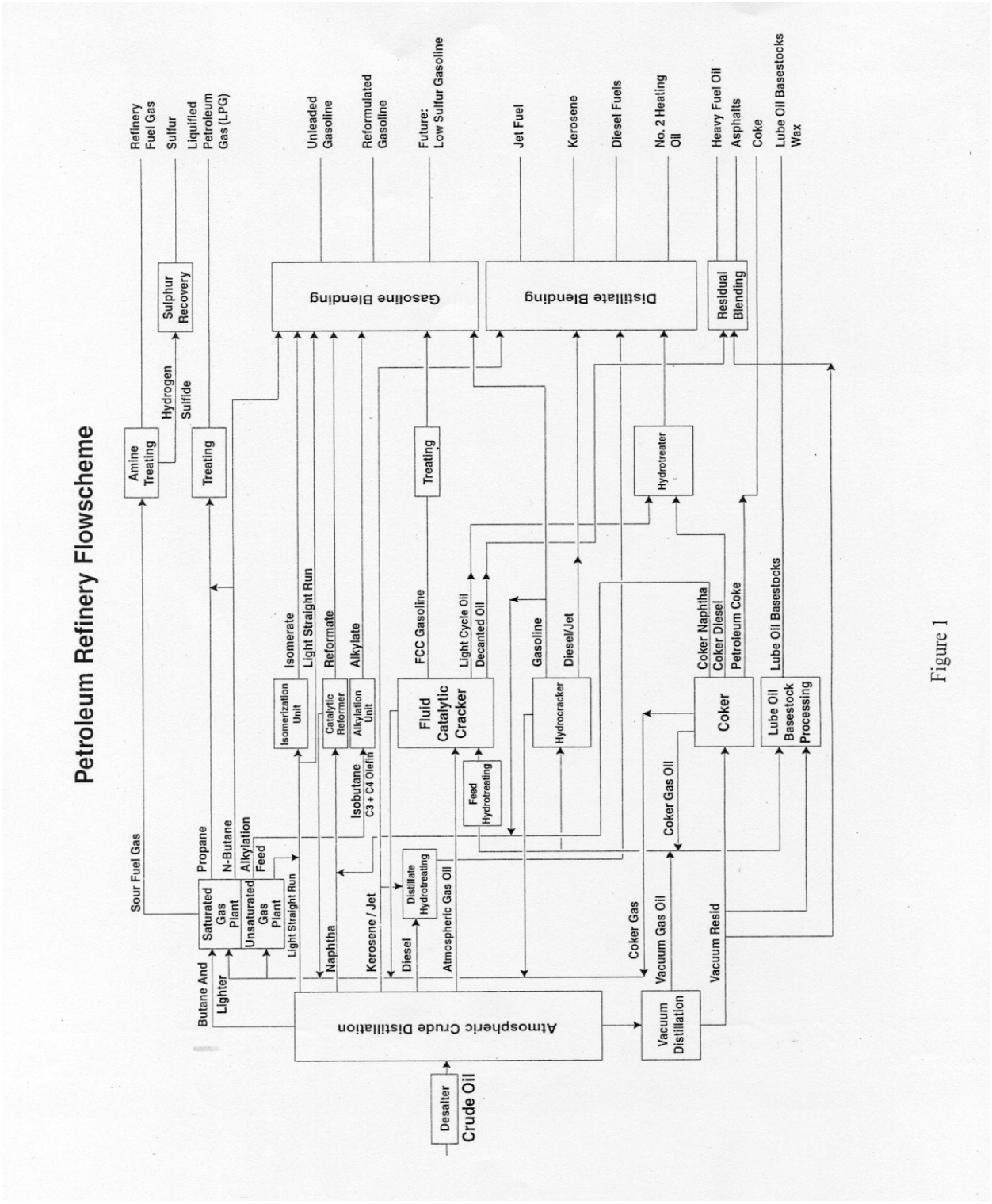
Petroleum Refinery Flowscheme
Refinery Fuel Gas
Sulfur
Liquified Petroleum Gas (LPG)
Unleaded Gasoline
Reformulated Gasoline
Future: Low Sulfur Gasoline
Jet Fuel
Kerosene
Diesel Fuels
No. 2 Heating Oil
Heavy Fuel Oil
Asphalts
Coke
Lube Oil Basestocks
Wax
Amine Treating
Hydrogen Sulfide
Sulphur Recovery
Treating
Gasoline Blending
Distillate Blending
Residual Blending
Hydrotreater
Isomerate
Light Straight Run
Reformate
Alkylate
FCC Gasoline
Light Cycle Oil
Decanted Oil
Gasoline
Diesel/Jet
Coker Naphtha
Coker Diesel
Petroleum Coke
Lube Oil Basestocks
Isomerization Unit
Catalytic Reformer
Alkylation Unit
Fluid Catalytic Cracker
Hydrocracker
Coker
Lube Oil Basestock Processing
Feed Hydrotreating
Isobutane
C3 + C4 Olefin
Coker Gas Oil
Sour Fuel Gas
Propane
N-Butane
Alkylation Feed
Saturated Gas Plant
Unsaturated Gas Plant
Light Straight Run
Distillate Hydrotreating
Naphtha
Kerosene / Jet
Diesel
Atmospheric Gas Oil
Coker Gas
Vacuum Gas Oil
Vacuum Resid
Butane And Lighter
Atmospheric Crude Distillation
Vacuum Distillation
Desalter
Crude Oil

Figure 1

Regulation No. 3 – Ambient Air Quality Standards:

This regulation is applicable to all affected emissions units in the refinery. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 6– Particulate Emissions from Construction and Materials Handling:

This regulation is applicable to all affected emissions units in the refinery where construction activity will take place. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 14 – Visible Emissions:

This regulation is applicable to all affected emissions units in the refinery. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 17 – Source Monitoring, Recordkeeping and Reporting:

Section 2.1 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, install, maintain, and use emission monitoring devices, keep records, and make periodic reports to the Department on the nature and amount of emissions from such source. The Department shall make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Compliance Methodology:

The Company shall install, maintain and use a flow monitoring device to determine the daily crude unit throughput.

Monitoring/Testing, Recordkeeping and Reporting:

None in addition to those required under Regulation No. 2.

Regulation No. 19 – Control of Odorous Air Contaminants

This regulation is applicable to all affected emissions units in the refinery. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 24 – Control of Volatile Organic Compound Emissions

Section 28 applies to any vacuum-producing system, wastewater separator, and process unit turnaround at petroleum refinery sources. No exemptions are allowable based on size or throughput of a facility.
This section is applicable to the crude unit because it contains vacuum producing systems. It is also applicable during unit turnarounds.

Standards.
Vacuum-producing systems: No person shall permit the emission of any uncondensed volatile organic compound (VOC) from the condensers, hot wells, or accumulators of any vacuum producing system at a petroleum refinery.

Process unit turnarounds: The Company shall provide for the following during process unit turnaround:

i. Depressurization venting of the process unit or vessel to a vapor recovery system, flare, or firebox.
ii. No emission of VOC from a process unit or vessel until its internal pressure is 136 kiloPascals (kPa) (19.7 pounds per square inch atmospheric [psia]) or less.

Compliance Methodology for Vacuum Producing Systems:

The standard shall be achieved by either of the following:

i. Piping the uncondensed vapors to a firebox or incinerator.
ii. Compressing the vapors and adding them to the refinery fuel gas.

Compliance Methodology for Process Unit Turnarounds:

The Company shall provide for the following during process unit turnarounds:

i. Depressurization venting of the process unit or vessel to a vapor recovery system, flare, or firebox.
ii. No emission of VOC from a process unit or vessel until its internal pressure is 136 kiloPascals (kPa) (19.7 pounds per square inch atmospheric [psia]) or less.

Recordkeeping and Reporting :

The Company shall keep records of the following items:

i. Date of every process unit or vessel turnaround; and
ii. The internal pressure of the process unit or vessel immediately prior to venting to the atmosphere.

Section 29: Leaks from Petroleum Refinery Equipment applies to all equipment in volatile organic compound (VOC) service in any process unit at a petroleum refinery, regardless of size or throughput.

Compliance Methodology:

The Company shall comply with the following standards in sub-sections c through h in Section 29 of Regulation no. 24.

c. Standards: General. The Company shall ensure that:
   1. Any open-ended line or valve is sealed with a second valve, blind flange, cap, or plug except during operations requiring process fluid flow through the open-ended line or valve.
   2. When a second valve is used, each open-ended line or valve equipped with a second valve is operated in such a manner that the valve on the process fluid end is closed before the second valve is closed.
   3. When a double block-and-bleed system is used, the bleed valve or line is open only during operations that require venting of the line between the block valves and is closed at all other times.

d. Standards: Equipment inspection program. The Company shall conduct the equipment inspection program described in paragraphs (d)(1) through (d)(3) of this Section using the test methods specified in **Appendix "F"** of this regulation.

   1. The Company shall conduct quarterly monitoring of each:
      i. Compressor.
      ii. Pump in light liquid service.
      iii. Valve in light liquid service, except as provided in paragraphs (e) and (f) of this Section.
      iv. Valve in gas/vapor service, except as provided in paragraphs (e) and (f) of this Section.

v. Pressure relief valve in gas/vapor service, except as provided in paragraphs (e) and (f) of this Section.

2. The Company shall conduct a weekly visual inspection of each pump in light liquid service.
3. The Company shall monitor each pressure relief valve after each overpressure relief to ensure that the valve has properly reseated and is not leaking.
4. When an instrument reading of 10,000 parts per million (ppm) or greater is measured, it shall be determined that a leak has been detected.
5. If there are indications of liquid dripping from the equipment, it shall be determined that a leak has been detected.
6. When a leak is detected, the Company shall affix a weatherproof, readily visible tag in a bright color bearing the equipment identification number and the date on which the leak was detected. This tag shall remain in place until the leaking equipment is repaired. The requirements of this paragraph apply to any leak detected by the equipment inspection program and to any leak from any equipment that is detected on the basis of sight, sound, or smell.

e. Standards: Alternative standards for valves:
Skip period leak detection and repair.

1. The Company shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in paragraph (d) of this Section.
2. After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
3. After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid.
4. If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in paragraph (d) of this Section but can again elect to use the requirements in paragraph (e) of this Section.
5. The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of this Section.
6. The Company shall keep a record of the percent of valves found leaking during each leak detection period.

f. Standards: Alternative standards for unsafe-to-monitor valves and difficult-to-monitor valves.

1. Any valve that is designated, as described in paragraph (j)(5)(i) of this Section, as an unsafe-to monitor valve is exempt from the requirements of paragraph (d) if:
   i. The Company of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as consequence of complying with paragraph (d).
   ii. The Company shall adhere to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.
2. Any valve that is designated, as described in paragraph (j)(5)(i), as a difficult-to monitor valve is exempt from the requirements of paragraph (d) if:
   i. The Company demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters (m) (6.6 feet [ft]) above a support surface.
   ii. The Company follows a written plan that requires monitoring of the valve at least once per calendar year.

g. Standards: Equipment repair program. The Company shall:
   1. Make a first attempt at repair for any leak not later than 5 calendar days after the leak is detected.
   2. Repair any leak as soon as practicable, but not later than 15 calendar days after it is detected except as provided in paragraph (h) of this Section.

h. Standards: Delay of repair.
   1. Delay of repair of equipment for which a leak has been detected is allowed if the repair is technically infeasible without a process unit shutdown. Repair of such equipment shall occur before the end of the next process unit shutdown.
   2. Delay of repair of equipment is allowed for equipment that is isolated from the process and that does not remain in VOC service.
   3. Delay of repair beyond a process unit shutdown is allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown is not allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

Monitoring/Testing:

The Company shall comply with the following testing procedures:
1. In conducting the tests required to comply with paragraph (d) of this Section, the Company shall use the test methods specified in **Appendix "F"** of this regulation

2. The Company shall test each piece of equipment as required under paragraph (d) of this Section unless it is demonstrated that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:
   i. Procedures that conform to the general methods in ASTM E260, E168, and E169 shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
   ii. Where the test methods in paragraph (i)(2)(i) also measure exempt compounds, these compounds may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.
   iii. Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in VOC service. If the Department disagrees with the judgment, paragraphs (i)(2)(i) and (i)(2)(ii) of this Section shall be used to resolve the disagreement.
3. The Company shall demonstrate that a piece of equipment is in light liquid service by showing one of the following:
   i. All of the following conditions apply:
      A. The vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C (0.044 in. Hg at 68°F); standard reference texts or ASTM D2879 shall be used to determine the vapor pressures.
      B. The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20°C (0.044 in. Hg at 68°F) is equal to or greater than 20 percent by weight.
      C. The fluid is a liquid at operating conditions.
   ii. The percent VOC evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM D86.
4. Samples used in conjunction with paragraphs (i)(2) and (i)(3) of this Section shall be representative of the process fluid that is contained in or contacts the equipment.

Recordkeeping:

The Company shall be subject to the following recordkeeping requirements:
1. Except as noted, these records shall be maintained in a readily accessible location for a minimum of 5 years and shall be made available to the Department immediately upon verbal or written request.
2. If there is more than one affected facility subject to the provisions of this Section the Company may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

3. When each leak is detected as specified in paragraph (d) of this Section, the following information shall be recorded in a log and shall be kept for 5 years in a readily accessible location:
   i. The instrument and operator identification numbers and the equipment identification number.
   ii. The date the leak was detected and the dates of each attempt to repair the leak.
   iii. The repair methods employed in each attempt to repair the leak.
   iv. The notation "Above 10,000" if the maximum instrument reading measured by the methods specified in **Appendix "F"** of this regulation after each repair attempt is equal to or greater than 10,000 ppm.
   v. The notation "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
   vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
   vii. The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.
   viii. The dates of process unit shutdowns that occur while the equipment is unrepaired.
   ix. The date of successful repair of the leak.
4. A list of identification numbers of equipment in vacuum service shall be recorded in a log that is kept in a readily accessible location.
5. The following information pertaining to all valves subject to the requirements of paragraph (f) of this Section shall be recorded in a log that is kept for 5 years in a readily accessible location:
   i. A list of identification numbers for valves that are designated as unsafe to monitor, an explanation for each valve stating why the valve is unsafe to monitor, and the plan for monitoring each valve.
   ii. A list of identification numbers for valves that are designated as difficult to monitor, an explanation for each valve stating why the valve is difficult to monitor, and the schedule for monitoring each valve.
6. The following information for valves complying with paragraph (e) of this Section shall be recorded in a log that is kept for 5 years in a readily accessible location:
   i. A schedule of monitoring.
   ii. The percent of valves found leaking during each monitoring period as noted in paragraph (e)(6) of this Section.
7. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept for 5 years in a readily accessible location for use in determining exemptions as provided in paragraph (a) of this Section.

Reporting.

The Company shall comply with the requirements in Section 5 of this regulation.

40 CFR 60, Subpart GGG

The provisions of this subpart apply to affected facilities in petroleum refineries. A compressor is an affected facility. In addition, the group of all the equipment (defined in §60.591) within a process unit is an affected facility.

Standards: The Company is subject to the provisions of this subpart shall comply with the requirements of §§60.482–1 to 60.482–10 as soon as practicable, but no later than 180 days after initial startup.

Compliance Methodology:

Compliance with this regulation is identical to the requirements under the refinery MACT in 40 CFR 63. Therefore, no additional discussion is presented here.

40 CFR 60, Subpart VV

The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

Compliance Methodology:

The Company shall demonstrate compliance with the requirements of §§60.482–1 through 60.482–10 or §60.480(e) for all equipment within 180 days of initial startup. The Company may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482–2, 60.482–3, 60.482–5, 60.482–6, 60.482–7, 60.482–8, and 60.482–10 as provided in §60.484. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482–2, 60.482–3, 60.482–5, 60.482–6, 60.482–7, 60.482–8, or 60.482–10, an owner or operator shall comply with the requirements of that determination. [18]

Monitoring/Testing:

The following monitoring/testing requirements are applicable:

[18] Equipment that is in vacuum service is excluded from the requirements of §§60.482–2 to 60.482–10 if it is identified as required in §60.486(e)(5).

(a) In conducting the performance tests required in §60.8, the Company shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The Company shall determine compliance with the standards in §§60.482, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The Company shall determine compliance with the no detectable emission standards in §§60.482–2(e), 60.482–3(i), 60.482–4, 60.482–7(f), and 60.482–10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The Company shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The Company shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 °C (1.2 in. H2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d) and (e) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

Recordkeeping requirements:

The following recordkeeping requirements are applicable:

(a) The Company shall comply with the recordkeeping requirements of section 60.486. Because there are more than one affected facility subject to the provisions of this subpart the Company may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10,000" if the maximum instrument reading measured by the methods specified in §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2, 60.482–3, 60.482–4, and 60.482–5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2, 60.482–3, 60.482–4, and 60.482–5.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1 to 60.482–10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2) (i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2(e), 60.482–3(i) and 60.482–7(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2(e), §60.482–3(i), or §60.482–7(f) shall be signed by the Company.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4.

(4) (i) The dates of each compliance test as required in §§60.482–2(e), 60.482–3(i), 60.482–4, and 60.482–7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7(g) and (h) and to all pumps subject to the requirements of §60.482–2(g) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2(d)(5) and 60.482–3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

Reporting requirements:

The following reporting requirements are applicable:

(a) The Company shall submit semiannual reports to the Department beginning six months after the initial startup date.

(b) The initial semiannual report shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7, excluding those valves designated for no detectable emissions under the provisions of §60.482–7(f).

(3) Number of pumps subject to the requirements of §60.482–2, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2(e) and those pumps complying with §60.482–2(f).

(4) Number of compressors subject to the requirements of §60.482–3, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3(i) and those compressors complying with §60.482–3(h).

(c) All semiannual reports to the Department shall include the following information, summarized from the information in §60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482(7)(b) or §60.483–2,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7(d)(1),

(iii)Number of pumps for which leaks were detected as described in §60.482–2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as described in §60.482–3(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) If the Company elects to comply with the provisions of §§60.483–1 or 60.483–2 it shall notify the Department of the alternative standard selected 90 days before implementing either of the provisions.

(e) The Company shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Department of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the State.

40 CFR 63, Subpart CC – NESHAP for Petroleum Refineries

This subpart applies to petroleum refining process units that are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and emit or have equipment

containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart. The refinery is a major source and the crude unit emits HAPs listed in table 1 of this subpart. Therefore, this is an applicable requirement.

Standards: The Company is subject to the provisions of this subpart shall comply with the requirements of §§60.482–1 to 60.482–10 as soon as practicable, but no later than 180 days after initial startup.

Compliance Methodology:

Compliance with this regulation is identical to the requirements under 40 CFR 60, subpart VV discussed above. Therefore, no additional discussion is presented

Consent Decree LDAR Requirements:

Paragraphs 114 and 115 of the federal CD establish an internal leak definition of 2000 ppm for pumps and 500 ppm for valves in light liquid and gaseous service. These leak thresholds are more restrictive than the standards in 40 CFR 60, subpart VV. Therefore, these are applicable requirements.

Compliance Methodology:

Because the leak detection threshold for pumps and valves in light liquid and gaseous service are more stringent than the levels in 40 CFR 60, subpart VV (2,000 ppm (CD)for pumps versus 10,000 ppm (NSPS) and 500 ppm (CD) for valves versus 10,000 ppm (NSPS)), the compliance methodology of the CD is applicable. This requires pumps to be monitored monthly and for repairs to be carried out according to the procedures in Section "F", paragraphs 116 through 118 of the CD

Monitoring/Testing:

The company shall comply with the monitoring requirements in paragraphs 119 through 121 of the CD

Recordkeeping and Reporting:

The Company shall comply with the recordkeeping and reporting requirements of paragraph 133 of the CD.

Crude Unit Atmospheric Heater (Unit 21-H-701):

Regulation No. 2 - Permits:
Section 2.1 (c) of this Regulation states:
Except as exempted in Section 2.2, no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department or, if eligible, prior to submitting to the Department a completed registration form for equipment, a facility or an air contaminant control device that is not subject to Section 2.1(a) or 2.1(b), the person shall submit to the Department an application for a permit pursuant to Section 11of this regulation.

Section 11.6 of this Regulation states:
No permit shall be issued by the Department unless the applicant shows to the satisfaction of the Department that the equipment, facility, or air contaminant control device is designed to operate or is operating without causing a violation of the State Implementation Plan, or any rule or regulation of the Department, and without interfering with the attainment or maintenance of National and State ambient air quality standards, and without endangering the health, safety, and welfare of the people of the State of Delaware. The Department may, from time to time, issue or accept criteria for the guidance of applicants indicating the technical specifications which it deems will comply with the performance standards referenced herein.

Furthermore, Section 11.8 states:
The following emission rates and/or standards for each air contaminant emitted from any equipment, facility or air contaminant control device shall be specified in each permit issued pursuant to this regulation:

*a. The rate and/or standard established and/or relied upon in the State Implementation Plan (SIP) to include the State of Delaware "**Regulations Governing the Control of Air Pollution**" and regulations promulgated pursuant to Section 111 and Section 112 of the Clean Air Act (CAA); and*

b. The rate that was shown under Section 11.6 as not interfering with the attainment and maintenance of any National and State ambient air quality standard, and not endangering the health, safety, and welfare of the people of the State of Delaware; or

c. The rate requested by the applicant. In no case shall this rate be greater than the potential to emit of the equipment, facility, or air contaminant control device; and in no case shall this rate be less stringent than the rate specified in Section 11.8(a) and (b) of this regulation.

This regulation is applicable to 21-H-701 since changes involve alteration of equipment that emits air contaminants.

21-H-701 was constructed in 1996 with a permitted design heat input capacity of 349 mmBtu/hour. It is fired by refinery fuel gas and also receives waste gas from a pre-combustor and selective non-catalytic reduction (SNCR) system that destroys the ammonia waste stream from the sour water stripper. It was subject to review under NSR because it was a major source that had a PTE to emit NO_x (a pre-cursor of a non-attainment pollutant, ozone) greater than the 25 TPY significance threshold. Two changes resulting from the PCUP will require a heat input revision to this unit. First, the crude unit's throughput will increase to 185,142 BPD; and second, the pre-combustor and SNCR system will be dismantled. The application requests a revised 21-H-701 heat input of 490 mmBtu/hour to accommodate these changes. AQM does not find the application to support the desired heat input increase for the following reasons:

- 21-H-701 is equipped with 24 Callidus burners (Model LE-CSG-14W), each with a 15.6 mmBtu/hour maximum heat release rate.[19]
- For unmodified heaters, the emissions increases attributable to the PCUP were estimated using a linear programming (LP) model by estimating the heat input increases attributable to the increase in crude throughput from 165 MBPD to 185 MBPD. The LP model predicted a net heat input increase of 18.3 mmBtu/hour to the crude unit vacuum heater. During technical discussions with the Company, AQM was given information that because the LP model does not distinguish between the crude unit vacuum heater and the crude unit atmospheric heater, the heat input increase was estimated based on the maximum firing rates for 21-H-2 and 21-H-701 (capacity weighted averages). If this approach is used, AQM calculated the heat input increase to 21-H-701 to be about 29 mmBtu/hour[20].
- Decommissioning the pre-combustor will result in a shortfall of merely 15 mmBtu/hour.[21]

Despite the above discussion, the Company insists that the revised heat input requirement should be 490 mmBtu/hour. Premcor has supplied the Department with documents which indicate operational changes were made to 21-H-701 that in effect rerated this unit[22]. Based on the

[19] A copy of the performance specification and vendor guarantees dated February 21, 1996 was submitted to the Department during the permit review of 21-H-701.
[20] 18.3 mmBtu/hour x 349 mmBtu/hour/221 mmBtu/hour. Premcor's response to AQM Questions/Discussion Items for July 27, 2004 Meeting.
[21] This shortfall will be made up by installing a new 15 mmBtu/hour burner in the firebox of 21-H-701.
[22] ABB Lumus e-mail as attachment to Technical Meeting Report on August 5, 2004.

requested heat input capacity of 490 mmBtu/hour, AQM has conducted an emissions comparison of the "past actual" to the "future potential" emissions which are summarized in Table 2.

Table 2: 21-H-701 Emission Comparison (TPY)

Pollutant	2001	2002	Average	PTE	Net Δ[23]
SO_2	23.8	22.9	23.4	48.1	24.7
NO_x	74.5	73.1	73.8	92.3	18.5
TSP	18.8	18.4	18.6	42.0	23.4
H_2SO_4	0.4	0.4	0.4	0.7	0.3
PM_{10}	19.3	18.8	19.0	42.9	23.9
CO	0	0	0	75.1	75.1
VOC	0.9	0.9	0.9	6.4	5.6
Pb	7.3 E-04	7.2 E -04	7.3 E -04	9.1 E-04	1.8 E -04

Emissions of criteria pollutants from a combustion source are a function of the heat input rate. Thus, as the firing rate increases from 349 mmBtu/hour to 490 mmBtu/hour, the emissions of all pollutants will increase proportionally. While some pollutants like NO_x are monitored continuously by means of continuous emissions monitoring systems (CEMS), others are not monitored. Compliance with the emissions limits for the unmonitored pollutants has to be based on stack test based emission factors and on the heat input rate. Furthermore, a performance test or stack test should be conducted during a period of operation that constitutes a "worst case scenario" for air emissions. The permit usually defines a maximum firing/process rate which constitutes the "worst case scenario." Under 40 CFR 60.8 Section (c) "Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests." The completion of a stack test program ensures compliance at a certain firing/process rate and will not be representative of emissions at higher firing/process rates. Therefore, the permit includes a condition that limits the firing rate of 21-H-701 to the requested rate of 490 mmBtu/hour.

Criteria pollutant emission limits for 21-H-701 are based on the following specifications and design data:

Design heat input of 490 mmBtu/hour
Vendor design guaranteed NO_x emission rate of 0.043 lb/mmBtu on a3 hour rolling average

[23] The increases shown in this column will not occur prior to commencement of operation of the FCU WGS

SO_2 emission factor of 0.022 lb/mmBtu based on 162 ppm H_2S in RFG
PM_{10} = TSP emission factor of 0.02 lb/mmBtu
CO emission factor of 0.035 lb/mmBtu
VOC emission factor of 0.003 lb/mmBtu
H_2SO_4 emission factor of 4.1 E-04 lb/mmBtu based on 1.2 % conversion of SO_2 to SO_3

PTEs (in tons per rolling twelve month period) were calculated as follows:

NO_x: [0.043 lb/mmBtu][490 mmBtu/hour][4.38 ton-hour/lb.year]
= 92.3 tons

SO_2: [0.022 lb/mmBtu][490 mmBtu/hour][4.38 ton-hour/lb.year]
= 48.1 tons

CO: [0.035 lb/mmBtu][490 mmBtu/hour][4.38 ton-hour/lb.year]
= 75.1 tons

VOCs: [0.003 lb/mmBtu][490 mmBtu/hour][4.38 ton-hour/lb.year]
= 6.4 tons

H_2SO_4: [0.022 lb SO_2/mmBtu][1.2 lb SO_3/100 lb SO_2][1 lb mole H_2SO_4/lb mole SO_3][98 lb H_2SO_4/lb mole H_2SO_4][1 lb mole SO_3/80 lb SO_3] [490 mmBtu/hour] [4.38 ton-hour/lb.year]
= 0.7 tons

PM_{10}: [0.02 lb/mmBtu][490 mmBtu/hour][4.38 ton-hour/lb.year]
= 42.9 tons (inclusive of 0.9 tons H_2SO_4)

Compliance Methodology:

The draft permit will include the following conditions[24]:

- The heat input to 21-H-701 shall not exceed 490 mmBtu/hour.
- NO_x emissions shall not exceed 0.043 lb/mmBtu on a rolling 3 hour average basis and 92.3 TPY
- SO_2 emissions shall not exceed 0.022 lb/mmBtu on a 3 hour average basis and 48.1 TPY
- CO emissions shall not exceed 0.035 lb/mmBtu and 75.1 TPY

[24] TPY is defined as "tons per rolling twelve months"

- VOC emissions shall not exceed 0.003 lb/mmBtu and 6.4 TPY
- Lead emissions shall not exceed 9.1 E-04 TPY

Monitoring/Testing:

The Company shall monitor the daily fuel flow to 21-H-701 and analyze daily representative samples of the fuel fired to obtain the HHV. Additional testing requirements are discussed under applicability of Regulation No. 17 below.

Recordkeeping:

The Company shall maintain records of the daily fuel usage and HHV.

Reporting:

The Company shall submit quarterly monthly reports due by the end of the following month after each quarter indicating each hour when the HHV exceeded 490 mmBtu/hour.

Regulation No. 3 – Ambient Air Quality Standards:

This regulation is applicable to all affected emissions units in the refinery. Therefore, it's applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 4– Particulate Emissions from Fuel Burning Equipment:

Section 2.1 states:
No person shall cause or allow the emission of particulate matter in excess of 0.3 pound per million BTU heat input, maximum 2-hour average, from any fuel burning equipment.

Compliance Methodology:

21-H-701 is equipped with Callidus LE-CSG-14W burners with a vendor guaranteed performance specification of 0.02 lb/mmBtu. Compliance with this standard shall be based on periodic testing. Since 0.02 lb/mmBtu is much smaller than the regulatory limit, compliance with the limit of 0.02 lb/mmBtu is sufficient to demonstrate compliance with the regulatory limit.

PTE = [0.02 lb/mmBtu][490 mmBtu/hour][8760 hours/year][5 E-04 ton/lb]
= 42.9 TPY

21-H-701 is presently operating in compliance with the permitted limit of 0.02 lb/mmBtu and the annual limit of 27.7 tons. However, based on the operating history of this unit and past stack tests, AQM is aware that the majority of the particulate matter emissions are contributed by the combustion of the waste stream from the sour water stripper (SWS) and the pre-combustor. The existing vendor guarantee of 0.02 lb PM_{10}/mmBtu was based on the 21-H-701 heater combusting RFG and the ammonia laden waste stream from the SWS and the pre-combustor. As part of the PCUP, the pre-combustor will be decommissioned and the SWS NH_3 stream will be rerouted to the SRA. Although, Premcor has sought an increase in the SRA's PM_{10} emissions limits, it has requested retaining the existing limit in the crude units permit with the rationale that past stack testing has shown non-compliance with the permit limit of 0.02 lb/mmBtu.

AQM is denying Premcor's request. Past diagnostic testing showed that processing the SWS waste stream in 21-H-701 has the potential to cause exceedances of the permit limit of 0.02 lb/mmBtu unless the SWS overhead accumulator (21-D-303) temperature is controlled to less than 107 º F on a 24 hour rolling average basis. Although, AQM will transfer this condition into the proposed permit to ensure the particulate loading to the SRA does not increase, it is reasonable to expect PM_{10} emissions from 21-H-701 to decrease from the current permitted level. Therefore, AQM is reserving the right to reassess the PM_{10} emission limits after additional testing is done and has developed the following permit condition:

PM_{10} emissions shall not exceed 0.02 lb/mmBtu and 42.9 TPY[25]. Compliance shall be demonstrated by the monitoring/testing requirements. The Company shall propose revised and reduced emission limits for the Department's approval that take into account the reduction in PM_{10} that occurs as a result of rerouting the SWS waste gas to the SRA within 60 days of completion of performance testing.

Monitoring/Testing

The Company shall conduct a Department approved stack test within 60 days of the unit achieving the maximum production at which 21-H-701 will be operated but not later than 180 days after initial start up and annually thereafter.

Recordkeeping:

The Company shall maintain records of stack test results, the daily fuel usage and HHV.

[25] "TPY" shall mean tons per rolling twelve month period.

Reporting:

The Company shall submit quarterly monthly reports due by the end of the following month after each quarter showing the rolling 12 month emissions and each exceedance.

Regulation No. 8– Sulfur Dioxide Emissions from Fuel Burning Equipment:

Section 2.1 states:

Except as provided in Section 2.2, no person shall offer for sale, sell, deliver, or purchase any fuel having a sulfur content greater than one (1.0) percent by weight when such fuel is intended for use in any fuel burning equipment in New Castle County. No person shall use any fuel having a sulfur content greater than one (1.0) percent by weight in any fuel burning equipment in New Castle County.

Compliance Methodology:

21-H-701 fires only natural gas or desulfurized refinery fuel gas which meets the NSPS criterion of 160 ppmvd H_2S in RFG. Therefore compliance with the regulatory limit shall be based on compliance with the NSPS limit.[26]

PTE = [0.022 lb/mmBtu][490 mmBtu/hour][8760 hours/year][5 E-04 ton/lb]
= 48.1 TPY

AQM has developed the following permit condition:

- Only natural gas or desulfurized RFG may be fired in 21-H-701.
- SO_2 emissions shall not exceed 0.022 lb/mmBtu and 48.1 TPY[27]. Compliance shall be based on meeting the NSPS limitation of 160 ppm H_2S in RFG on a 3 hour average basis.

Monitoring/Testing

[26] 160 ppmvd translates to 0.022 lb/mmBtu based on the following calculation: [160 ppm $H_2S/10^6$ parts RFG][1 mol H_2S/385.3 SCF H_2S][1 mol SO_2/1 mol H_2S][64 lb SO_2/ 1 mol SO_2][1 SCF RFG/1,180 Btu][10^6 Btu/mmBtu]

[27] "TPY" shall mean tons per rolling twelve month period.

The Company shall continuously monitor the H_2S content of the RFG using a CEMS before it is combusted in 21-H-701. The CEMS shall comply with the requirements of 40 CFR 60, Appendix "B" and the QA procedures shall be in accordance with 40 CFR 60, Appendix "F".

Recordkeeping:

The Company shall maintain records of stack test results, the daily fuel usage and HHV.

Reporting:

The Company shall submit quarterly monthly reports due by the end of the following month after each quarter showing the rolling 12 month emissions and each exceedance.

Regulation No. 9 – Emissions of Sulfur Compounds from Industrial Operations:

This regulation specifies that SO_2 emissions from process operations shall be controlled to a limit that shall meet the ambient air quality requirements. Compliance with this regulation is subsumed in the discussion under the applicability of 40 CFR 60, subpart "J". Therefore, no additional discussion is provided here.

Regulation No. 12:

Regulation No. 12 is applicable for all fuel burning equipment with a rated heat input greater than 15 mmBtu/hour. Unit 21-H-701 will have a rated heat input of 490 mmBtu/hour. Therefore, this heater unit is subject to Regulation 12.

Section 3.1 of Regulation 12 requires *that except as set forth in Sections 5 and 6, after May 31, 1995, no owner or operator of a major NO_x emitting source subject to the provisions of this Regulation shall cause to be discharged into the atmosphere any emission of nitrogen oxides without using reasonably available control technology.*

Section 3.2 of Regulation 12 requires *that the maximum allowable emission rates of nitrogen oxides from fuel burning equipment with a rated heat input capacity of 100 MMBTU/hr or greater shall be established as follows:*
a) Existing fuel burning equipment shall be presumed to meet the definition of reasonably available control technology if the owner or operator demonstrates to the satisfaction of the Department that the emission levels in Table I can be met.
b) If the owner or operator does not make the demonstration described in paragraph a of this section, RACT shall be installed with the goal of achieving the presumptive emission limits as set

forth in Table I. RACT for this category of equipment will consist of combustion modification technology including either:
i) low NO_x burner technology with low excess air and including Over Fire Air if technically feasible; or
ii) flue gas recirculation with low excess air. If actual achievable emission levels following installation of such combustion modification technology are greater than the presumptive emission limits in Table I, these actual emission levels will become RACT for those sources. Compliance with the emission levels as determined above is based upon twenty-four hour rolling averaging period as follows:
i) For fuel burning equipment with a rated heat input of 250 MMBTU/hr of greater Continuous Emission Monitoring Systems (CEMS) approved by the Department will be used.
ii) For fuel burning equipment with a rated heat input of 150 MMBTU/hr or greater but less than 250 MMBTU/hr compliance will be based on:
A) a CEMS approved by the Department; or
B) at the sources' request, an enhanced monitoring program approved by the Department. This enhanced monitoring program will identify and correlate various operating parameters with NO_x emission levels through source testing. These parameters will be used as surrogates to monitor NO_x emissions. Periodic source testing will be required to verify the validity of these surrogate parameters.

Compliance Determination Methodology for Regulation No. 12

Unit 21-H-701 has an emission limit of 0.043 lb/mmBtu on a 3 hour average and a RACT limit of 0.2 lb/mmBtu on a 24 hour rolling average basis. Compliance is based on a time shared CEMS with 21-H-2.

Monitoring and Testing:
The NO_x and CO_2 CEMS shall meet the applicable Performance Specifications in 40 CFR, Part 75, Appendix "A". The Quality Assurance/Quality Control (QA/QC) procedures for NO_x and CO_2 CEMS shall be established in accordance with 40 CFR Part 75, Appendix "B".

Recordkeeping:
The Company shall maintain the following records in addition to complying with the general recordkeeping requirements of Condition 3(b)(2) of the attached permit

- CEMS calibration and audit results
- F-factor adjustments
- Actual daily data capture

Reporting:

The Company shall submit quarterly reports of the following reports:

- A written report shall be submitted for each excess NO_x emission within thirty (30) days of the initial report, with the following information:
  - ► The name and location of the facility;
  - ► The permitted source(s) that caused the excess emission;
  - ► The time and date of the first observance of the excess emission;
  - ► The cause and expected duration of the excess emission;
  - ► The estimated rate of emissions (expressed in the units of applicable emission limitation) and the operating data and calculations causing the excess emissions;
  - ► The proposed corrective actions and schedule to correct the conditions causing the excess emissions.

! A summary of all NO_x excess emissions for the quarter;

! CEMS report to include system calibration and audit results, F-factor adjustments, and the actual daily data capture for the period;

! Higher heating values of refinery fuel gas obtained daily

Regulation No. 14 – Visible Emissions:

This regulation is applicable to all affected emissions units in the refinery. Therefore, it's applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 17 – Source Monitoring, Recordkeeping and Reporting:

Section 2.1 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, install, maintain, and use emission monitoring devices, keep records, and make periodic reports to the Department on the nature and amount of emissions from such source. The Department shall make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, sample the emissions of, or fuel used by, that source, maintain records and submit reports to the Department on the results of such sampling. The Department may make

such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
The Department may conduct tests of emissions from or fuel used by any air contaminant source. Upon written request of the Department, the owner or operator of the air contaminant source shall provide necessary holes in stacks or ducts, and such other safe and proper sampling and testing facilities, exclusive of instruments and sampling devices, if any are necessary, for proper determinations of the emission of air contaminants. The Department shall have access to and use of monitoring, record-keeping and reporting required by Federal Regulations relating to emissions of air contaminants. The Department may make such data available to the public as reported or received and as correlated with any applicable emissions standards or limitations.

Compliance Methodology:

Compliance shall be based on the monitoring/testing requirements

Monitoring/Testing, Recordkeeping and Reporting:

Unit 21-H-701 is equipped with a CEMS to monitor the NO_x emissions. Compliance with the NO_x emissions limitations shall continue to be based on the CEMS.
Compliance with the SO_2 emissions limit shall be based on the monthly fuel usage and the average H_2S in RFG as determined by CEMS.

For CO, VOCs and PM_{10}: Annual stack tests shall be conducted until such time as the ammonia gas from the sour water stripper is routed to the sulfur recovery units to verify compliance with the lb/mmBtu limits. The stack test based emissions factors and the rolling twelve month fuel usage shall be used to determine compliance with the annual (rolling twelve month) limits. A "Source Sampling Guidelines and Preliminary Survey Form" shall be submitted and found acceptable by the Department at least thirty (30) days prior to the stack emission testing. Results of the stack emission testing shall be submitted to the Department, in triplicate, no later than ninety (90) days after completion of the testing. After completion of the rerouting of the ammonia stream to the SRA, the frequency of testing shall be once every 2 years.

Recordkeeping:

The Company shall maintain records of CEMS data, stack test results, the daily fuel usage and HHV.

Reporting:

Quarterly reports for the preceding quarter shall be submitted to the Department by January 31, April 30, July 31 and October 31 of each calendar year with the following information:

- A summary of all NO_x excess emissions for the quarter;
- CEMS report to include system calibration and audit results, F-factor adjustments, and the actual daily data capture for the period;
- Higher heating values

Regulation No. 19 – Control of Odorous Air Contaminants

This regulation is applicable to all affected emissions units in the refinery. Therefore, it's applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 20 & 40 CFR Part 60, Subpart "J" - New Source Performance Standards for Petroleum Refineries:

The requirements of Regulation No. 20, Section 11 incorporate by reference 40 CFR 60, Subpart "J" - the federal NSPS for petroleum refineries. The NSPS standard limits the maximum hydrogen sulfide (H_2S) content in refinery fuel gas to 0.1 grain/DSCF (230 mg/DSCM) on a three hour rolling average basis.

Compliance Determination Methodology for Regulation No. 20 and 40 CFR 60, Subpart "J":

The Company continuously monitors the H_2S content in the RFG on a three hour rolling average basis before the RFG is combusted in any fuel burning device. This is an acceptable method. The existing Regulation No. 2 permit condition also requires that the H_2S content in the RFG be monitored continuously. However, because there was no existing performance specification at the time for H_2S monitors, the Department reserved the right to require them in the event that such specifications are established. Since then, Performance Specification 7 in 40 CFR 60, Appendix "B" for H_2S CEMS in stationary sources has been established. Therefore, it is recommended that a permit condition be included that requires conformance with 40 CFR 60, Appendix "B" and with 40 CFR 60, Appendix "F" for Quality Assurance requirements

Monitoring & Testing:

The CEMS to monitor H_2S in RFG shall conform to the requirements of 40 CFR 60, Appendix "B" and the QA procedures shall be in accordance with 40 CFR 60, Appendix "F

Record Keeping:

The Company shall maintain records of all three hour rolling averages of the H_2S content in the RFG.

Reporting:

The Company shall comply with the following reporting requirements:

- Notification of any physical or operational change which may increase the emission rate of any pollutant to which a standard applies. Such notification shall be postmarked 60 days or as soon as practicable before the change is commenced.
- Thirty day notification prior to conducting Relative Accuracy Test Audits (RATAs) or Cylinder Gas Audits (CGAs).
- Quarterly excess emissions reports (EERs) identifying all periods when the rolling three hour average H_2S concentration in RFG exceeds 0.1 gr/dscf. The EERs shall include the following:
  - the magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used and the date and time of commencement and completion of each time period of excess emissions
  - Specific identification of each period of excess emissions that occurs during start ups, shutdowns, and malfunction, the corrective action taken or preventative measures adopted
  - The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
  - When no excess emissions have occurred or the CEMS has not been inoperative, repaired or adjusted, such information shall be stated in the report.

Regulation No. 39 – Nitrogen Oxides Budget Trading Program:[28]

Section 2 of Regulation 39 states:

[28] The requirements of Regulation 39 are unaffected by the PCUP. The discussion on the applicability of this regulation is included for completeness. Since all the Regulation 39 requirements are already included in the NO_x Budget Permit, these requirements are not being repeated in this permitting action.

a. *Each NO_x Budget unit shall hold in its compliance account and/or its overdraft account, as of the NOX allowance transfer deadline of each control period, a quantity of NO_X allowances available for deduction that is equal to or greater than the total NO_X emissions from that NOX Budget unit for that control period.*
b. *Each NOX Budget unit shall be subject to the requirements of Section 2(a) of this regulation starting on the later of May 1, 2003 or the date the unit commences operation.*

Unit 21-H-701 will have a rated heat input of 490 mmBtu/hour. Therefore, it is an affected unit under the NO_x Budget Trading Program.

Compliance Determination Methodology for Regulation No. 39:

Compliance is based on operating a certified CEMS and the recordkeeping and reporting requirements.

Monitoring & Testing:

1. The Company and, to the extent applicable, the NOx authorized account representative of each NOx Budget source and each NOx Budget unit at the source shall comply with the monitoring requirements of Regulation No. 39 § 8.
2. The emissions measurements recorded and reported in accordance with Regulation No. 39 § 8 shall be used to determine compliance by the unit with the NOx Budget emissions limitation under paragraph (c).

Record Keeping and Reporting:

Unless otherwise provided, the owners and operators of the NOx Budget source and each NOx Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

a. The account certificate of representation under Regulation No. 39 § 6 and all documents that demonstrate the truth of the statements in the account certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new account certificate of representation under Regulation No. 39 § 6 changing the NOx authorized account representative.

b. All emissions monitoring information, in accordance with Regulation No. 39 § 8; provided that to the extent that Regulation No. 39 § 5 provides for a 3 year period for record keeping, the 3 year period shall apply.
c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the NOx Budget Trading Program.
d. Copies of all documents used to complete a NOx Budget permit application and any other submission under the NOx Budget Trading Program or to demonstrate compliance with the requirements of the NOx Budget Trading Program.
e. Records demonstrating that any unit exempted under Regulation No. 39 § 3(b) of this regulation is retired. The owner(s) or operator(s) of that unit bears the burden of proof that the unit is retired.
f. The NOx authorized account representative of a NOx Budget source and each NOx Budget unit at the source shall submit the reports and compliance certifications required under the NOx Budget Trading Program, including those under Regulation No. 39 § 7, 8, and 11.
g. Each document submitted to the Department and the Administrator pursuant to this permit shall be signed and certified by the Authorized Account Representative and shall contain the following language:
"I am authorized to make this submission on behalf of the owners and operators of the NOx Budget sources or NOx Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

Fluid Coking Unit (FCU)(Unit 22):

Regulation No. 2 - Permits:
Section 2.1 (c) of this Regulation states:
Except as exempted in Section 2.2, no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department or, if eligible, prior to submitting to the Department a completed registration form for equipment, a facility or an air contaminant control device that is not subject to Section 2.1(a) or 2.1(b), the person shall submit to the Department an application for a permit pursuant to Section 11of this regulation.

Section 11.6 of this Regulation states:
No permit shall be issued by the Department unless the applicant shows to the satisfaction of the Department that the equipment, facility, or air contaminant control device is designed to operate or is operating without causing a violation of the State Implementation Plan, or any rule or regulation of the Department, and without interfering with the attainment or maintenance of National and State ambient air quality standards, and without endangering the health, safety, and welfare of the people of the State of Delaware. The Department may, from time to time, issue or accept criteria for the guidance of applicants indicating the technical specifications which it deems will comply with the performance standards referenced herein.

Furthermore, Section 11.8 states:
The following emission rates and/or standards for each air contaminant emitted from any equipment, facility or air contaminant control device shall be specified in each permit issued pursuant to this regulation:

*a. The rate and/or standard established and/or relied upon in the State Implementation Plan (SIP) to include the State of Delaware "**Regulations Governing the Control of Air Pollution**" and regulations promulgated pursuant to Section 111 and Section 112 of the Clean Air Act (CAA); and*

b. The rate that was shown under Section 11.6 as not interfering with the attainment and maintenance of any National and State ambient air quality standard, and not endangering the health, safety, and welfare of the people of the State of Delaware; or

c. The rate requested by the applicant. In no case shall this rate be greater than the potential to emit of the equipment, facility, or air contaminant control device; and in no case shall this rate be less stringent than the rate specified in Section 11.8(a) and (b) of this regulation.

This regulation is applicable to the FCU and the FCU COB since changes involve alteration of equipment that emits air contaminants. Table 3 shows the FCU emissions comparison between the average baseline emissions of 2000-2001 and the PTEs after implementation of the PCUP.

Table 3: FCU Emissions Comparison (TPY)

Pollutant	2001	2002	Average	PTE	Net Δ
SO_2	18971.2	19460.6	19,215.9	173.8	-19042.2
NO_x	749.3	630.3	689.8	457	-232.8
TSP	247.1	306.1	276.6	206.3	-70.3
H_2SO_4	265.4	272.3	268.8	252.2	-16.7
PM_{10}	512.2	578.3	545.4	458.5	-86.9
CO	1382.2	1210.5	1296.3	416	-880.3
VOC	110.5	96.5	103.5	43.8	-59.7

Pb	6.8 E-02	7.0 E -02	6.9 E -02	9.0 E-02	2.1 E -02
TRS/RSC	5.8 E-03	5.9 E-03	5.8 E-03	7.6 E-03	1.8 E-03
H_2S	5.8 E-03	5.9 E-03	5.8 E-03	7.6 E-03	1.8 E-03

Emissions of criteria pollutants from the FCU vary with the unit throughput, coke burn rate and sulfur and nitrogen content in the feed, and other process operating parameters. Thus, as the throughput and the coke burn rate increase, the emissions of all pollutants will increase proportionally. While some pollutants like NO_x are monitored continuously by means of continuous emissions monitoring systems (CEMS), others are not monitored. Compliance with the emissions limits for the unmonitored pollutants has to be based on stack test based emission factors and on the throughput and coke burn rate. Furthermore, a performance test or stack test should be conducted during a period of operation that constitutes a "worst case scenario" for air emissions. The permit usually defines a maximum firing/process rate which constitutes the "worst case scenario." Under 40 CFR 60.8 Section (c) "Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests." The completion of a stack test program ensures compliance at a certain firing/process rate and will not be representative of emissions at higher firing/process rates. Therefore, the permit includes a condition that limits the FCU throughput and coke burn rate to 20,884 Mbbl and 412,596 Mlb, respectively, both on a rolling 365 day basis.

The following technical analysis discusses the emissions changes associated with each pollutant based on the assumptions and design specifications given below:

Sulfur dioxide (SO_2)

Gas flow to scrubber, $Q_{i,w}$: 40,262 lb.mole/hour (wet)
Moisture content, % H_2O: 26.7 mole %
Oxygen content, % $O_{2,w}$: 2.39 mole %
Inlet SO_2 concentration $SO_{2,i,d,0\%\,O2}$; 4300 ppmvd
Outlet SO_2 concentration $SO_{2,o,d,0\%\,O2}$; 25 ppmvd

The FCU WGS flow data is represented by the following equation:

$$Q_{i,d@0\%O2} = Q_{i,w}\left[1-\frac{\%H_2O}{100}\right]\left[1-\left\{\frac{\%O_{2,w}/100}{1-(\%H_2O/100)}+\frac{79}{21}\left(\frac{\%O_{2,i,w}}{1-(\%H_2O/100)}\right)\right\}\right]$$

$$Q_{o,d,0\%O2} = Q_{i,d,0\%O2}\left[1 - \left(\frac{SO_{2,i} - 25}{10^6}\right)\right]$$

Based on the above assumptions:
Moisture corrected inlet gas flow, $Q_{i,d}$: [40,262 lb.mole/hour][1- $\%H_2O/100$]
= 29,508 lb.mole/hour

Then, the O_2 and moisture corrected inlet gas flow, $Q_{i,d,0\%O2}$ is given by the expression:
$[Q_{i,,w}][1- \%H_2O/100]$ $[1-\{(\%O_{2,i,w}/100)/(1- \%H_2O/100) + 79/21(\%O_{2,i,w}/100)/(1- \%H_2O/100)]$
= [40,262 lb.mole/hour][1- 0.2671][(1-{(0.0326 + 79/21(0.0326)}] lb-mole/hour
= 24,919 lb.mole/hour

The WGS is expected to lower the exit concentration of SO_2 from 4300 ppmvd to 25 ppmvd. When this adjustment is applied, the equation for the outlet gas flow under dry, oxygen free and clean condition will be given by the expression:
$Q_{o,d,0\%O2,clean}$ = [$Q_{i,d,0\%O2}$][1- {$(4300-25)/10^6$}]
= 24,919 [1- $4275/10^6$]
= 24806 lb.mole/hour

The contaminant emission rate is: [25 parts SO_2 /10^6 parts of flue gas][$Q_{o,d,0\%O2,clean}$]
= [24806 lb.mole flue gas/hour][25 parts SO_2 /10^6 parts of flue gas]
= 0.64 lb.mole SO_2/hour
= 174 TPY

Nitrogen oxides (NO_x):

The FCU COB will accommodate the SNCR system. The COB is an opposed wall fired boiler manufactured by Babcock and Wilcox that predominantly operates in a base-loaded mode which nominally generates 390,000 lb/hour steam at 600 psig and 750 deg. F but has a design rating of 430,000 lb/hour. Feed water temp is 310 deg. F. The boiler has 4 S type burners that are arranged on a single elevation with two burners each opposite wall. The furnace is 20 feet wide, 20.5 feet deep and 55 feet high from the CO gas plenum exit to the boiler roof.

As shown in Table 3 baseline NO_x emissions are 689.8 TPY. The Company has sought a permit limit of 714.7 TPY. However, this limit is not supported by the information in the application. Based on the information in Premcor's application, AQM has calculated the FCU NO_x PTE as follows:

Using the GE EER Phase II Final Report:

This report guarantees NO_x emissions of less than 78 ppmvd @ 3 % O_2 and 20 ppmvd NH_3 slip also corrected to @ 3 % O_2. NH_3 slip of 20 ppmvd @ 3 % O_2 is expected to result when the predicted optimum nitrogen stoichiometric ratio of 1.5 is maintained in the SNCR system.
The design baseline case material balance indicates a design NO_x concentration of 128 ppmvd @ 3 % O_2 when the FCU COB was generating 410 klb/hour steam and at a coke burn rate of 53,000 lb/hour. GE EER guarantees a 40 % reduction at 130 ppm NO_x @ 3 % O_2.
Corrected to 0 % O_2, this guarantee becomes: 78 ppmvd (21-0)/(21-3)
= 91 ppmvd @ 0 % O_2

NO_x PTE = [(91 ppmvd)/10^6] [24806 lb. mole/hour][46 lb NO_x/lb.mole] [4.38 ton-hour/lb.year]
= 454 TPY

This approach is consistent with the figures shown in the material balance in the application. Section 5 & Appendix "A": The FCU material balance accompanying the AQM-4 application indicates stream 1 (COB flue gas) in the PFD to consist of 108 lb as nitric oxide and 9 lb as nitrogen dioxide. AQM calculates the combined NO_x in stream 1 to be 174.6 lb/hour as NO_2. Based on the flow of 254,294 scfm (wet) and a moisture fraction of 26.7 % upstream of the pre-scrubber, AQM verified the NO_x concentration to be 130 ppm (dry) @ 3 % O_2 [29]. This figure is consistent with the GE report which guarantees an exit NO_x concentration of 78 ppm (dry) @ 3 % O_2 from the SNCR system based on an inlet of 130 ppm (dry) @ 3 % O_2 to the SNCR. When the 40 % guaranteed control efficiency is applied, NO_x in stream 1 will be reduced to 64.6 lb as nitric oxide (99 lb/hour as NO_2) and 5.4 lb as nitrogen dioxide which translates to a rolling twelve month potential to emit figure of 457 TPY as NO_x.

Alternately, AQM evaluated the expected reductions measured from the baseline emission level of 689.8 TPY. If this approach is used the resulting PTE becomes 414 TPY.[30] Although, this method gives a lower PTE, AQM is recommending the limit of 457 TPY based on the GE report because of the following reasons:

- The GE EER report guarantees the NO_x emissions at 78 ppmvd @ 3 % O_2 after conducting a detailed analysis using computational fluid dynamics to determine

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[29] Flow corrected to dry condition = [254,294 scfm][1 – 0.267] = 186,372 dscfm
Therefore, $NO_{x,\ 3.26\ \%\ O2}$ (ppmvd) = [175 lb NO_x/hr][385.3 dscf/lb.mole][(182,376 dscfm)(60 min/hr)]$^{-1}$[10^6] / 46 lb NO_x/ lb. mole NO_x]
= 131 ppmvd
And $NO_{x,\ 3.26\ \%\ O2}$ (ppmvd) at the SNCR outlet = [131 ppmvd][1 -0.6]
= 78 ppmvd

[30] PTE based on 40 % vendor guaranteed reduction for the SNCR system results in [689,8 TPY][0.6] = 414 TPY.

combustion and flow characteristics based on temperature and species distribution in the coker under baseline operating conditions.

- The baseline model was calibrated against field temperature and species data by varying a turbulent mixing model and coker CFD boundary conditions. The calibrated baseline flow was then used in conjunction with a simplified chemistry set to estimate SNCR performance at boundary conditions for various NH_3 injection schemes such as injector biasing, injector yaw, and location variation and coker operating scenarios such as burners out of service and burner swirl adjustments.
- The permit will provide for optimization of the SNCR system to get incremental reductions.

With regard to the ammonia slip, 20 ppmvd @ 3% O_2 appears to be a fairly high slip. This translates to 23.4 ppmvd at 0 % O_2.[31]

23.4 ppm NH_3 at 0 % O_2 translates to 43 TPY.[32]

AQM expects the actual NH_3 emissions to be much smaller than the calculated PTE for two reasons. First, simplified heat transfer calculations suggest the boiler economizer tube temperatures will be within about 10 deg F of the bulk feed water temperature, and therefore potentially in the range that favors sulfate formation. Thus some of the ammonia slip will be converted to sulfate that can be expected to precipitate on the downstream heat transfer surfaces in the economizer. Second, the downstream pre-scrubber and wet gas scrubber can be expected to remove virtually all the ammonia in the flue gas. The material balance sheet indicates a stack discharge of 2 lb/hour (8.8 TPY). It is AQM's assessment that 8.8 TPY is an appropriate permit limit.

Total suspended Particulate (TSP) Matter:

Baseline emissions are 276.6 TPY
The PTE is based on the vendor (Belco) pre-scrubber guarantee is 47.1 lb/hour (filterable)
= [47.1 lb/hour][4.38 ton-hour/lb.year]
= 206.3 TPY

Sulfuric Acid (H_2SO_4):

[31] NH_3 @ 0 % O_2 = [20 ppm][20.9/(20.9-3)] = 23.4 ppmvd @ 0 % O_2
[32] PTE NH_3 = [23.4/10^6][24806 lb.mole/hour][17 lb NH_3/lb.mole][5 E-04 ton-hour/lb.year]
= 43.1 tPY

Baseline emissions are 268.8 TPY.
The PTE is based on the vendor (Belco) pre-scrubber guarantee is 40 % capture of SO_3 resulting in 39.3 ppmvd @ 0 % O_2[33]
The SO_3 design concentration in turn is based on 0.91 % conversion of the design SO_2 inlet concentration of 4300 ppmvd @ 0 % O_2

SO_3 PTE = [(39.3 ppmvd)/10^6] [24806 lb. mole/hour]
= 0.98 lb.mole/hour

H_2SO_4 PTE: = [0.98 lb.mole SO_3/hour][1 lb mole H_2SO_4/1 lb.mole SO_3][98 lb H_2SO_4/lb mole H_2SO_4][4.38 ton-hour/lb.year]
= 252.2 TPY

Particulate Matter with an Aerodynamic Diameter Less than 10 Microns (PM_{10}):

Baseline emissions are 545.4 TPY
The PTE based on all particulate emissions being PM_{10}.
Thus, PTE PM_{10} = PTE TSP + PTE H_2SO_4
= 206.3 + 252.2
= 458.5 TPY

Carbon Monoxide (CO):

Baseline CO emissions were calculated using the *FIRE 6.24* emission factor for petroleum refinery fuel gas combustion (35 lb CO/mmSCF process gas)
Baseline = 1296.3 TPY
Premcor has requested a PTE of 1,809.4 TPY based on the FCU having an uncorrected CO exit concentration that is less than 500 ppmvd.

Thus PTE CO = [$Q_{i,d}$][500/10^6][1 lb.mole/385.5 DSCF][28 lb CO/lb.mole CO][385.5 DSCF/lb.mole][4.38 Ton-hour/lb.year]
= [29508 lb.mole/hour][1 lb.mole/385.5 DSCF][28 lb CO/lb.mole CO][385.5 DSCF/lb.mole][4.38 Ton-hour/lb.year]
= 1809 TPY

AQM reviewed the material balance submitted with the application and finds the design CO emission rate of 95 lb/hour which translates to 416 TPY. When queried about the reason for the disparity, the Company's response was to revise the material balance to make it consistent with the 500 ppmvd (O_2 uncorrected) emission level. AQM's finds that that the assumption of 500

[33] SO_3 concentration = [4300 ppmvd SO_2][0.91 ppm SO_3/100/ ppmvd SO_2] = 39.3 ppmvd SO_3 @ 0 % O_2

ppmvd (O_2 uncorrected) in the FCU stack is an arbitrary figure because it has never been confirmed by a stack test. Furthermore, the only basis suggested by the Company is that the FCU CO limit is similar to CO emissions from the FCCU which has an NSPS limit of 500 ppm. During technical discussions, the Company indicated an emission limit of 416 TPY is not attainable. AQM disagrees, pending verification by a stack test to be performed under representative operating conditions to determine the baseline CO emission concentration which can then be used to calculate the annual CO emissions from the value of the designed uncorrected dry flow condition.

Volatile Organic Compounds (VOCs):

Baseline VOC emissions were calculated using the *FIRE 6.23* emission factor for petroleum refinery fuel gas combustion (2.8 lb VOC/mmSCF process gas)
Baseline = 103.5 TPY
Premcor has requested a PTE of 116.4 TPY based on the FCU COB combusting a mix of 0.5 mmSCF/hour of RFG and 9 mmSCF/hour of process off gas. The Company has used the same emission factor for both fuels, i.e 2.8 lb VOC/mmSCF.
Thus PTE VOC = [2.8 lb VOC/mmSCF][9.5 mmSCF/hour][4.38 Ton-hour/lb.year]
= 116 TPY.

AQM reviewed the material balance submitted with the application and finds the design VOC emission rate of 10 lb/hour as CH_4 which translates to 43.8 TPY. When queried about the reason for the disparity, the Company's response was to revise the material balance to make it consistent with the emission level sought, i.e., 116 TPY. AQM finds this approach unacceptable because it uses an arbitrary figure that has never been confirmed by a stack test. During technical discussions, the Company indicated an emission limit of 43.8 TPY is not attainable. AQM disagrees, pending verification by a stack test to be performed under representative operating conditions to determine the baseline VOC emission concentration which can then be used to calculate the annual VOC emissions from the value of the designed uncorrected dry flow condition.

Lead (Pb), Hydrogen Sulfide (H_2S) and Reduced Sulfur Compounds (RSC):

Baseline Pb emissions were determined using guidance from Exxon R&E. This emission factor (4.37 E-04 lb Pb/Mlb coke) is stated as a function of the coke burn rate. Baseline coke burn rates in turn were calculated as a function of the ratio of the actual charge rate to the maximum charge rate.

2001 charge rate = 15,839 Bbl/year

2002 charge rate = 16,248 Bbl/year
Max. charge rate = 20,884 Bbl/year
Max. coke burn rate = [47.1 Mlb/hour x 8760 hours/year]
= 412596 Mlb/year

2001 Pb emissions = [4.37 E-04 lb Pb/Mlb coke][15839 MBbl/yr/20884 MBbl/year] [412596 Mlb/year][1 ton/2000 lb]
= 6.84 E-02 TPY
2002 Pb emissions = [4.37 E-04 lb Pb/Mlb coke][16248 MBbl/yr/20884 MBbl/year] [412596 Mlb/year][1 ton/2000 lb]
= 7.01 E-02 TPY

PTE Pb = [4.37 E-04 lb Pb/Mlb coke][412596 Mlb/year][1 ton/2000 lb]
= 9.02 E-02 TPY

Baseline RSC/H_2S emissions were determined using guidance from Exxon R&E. This emission factor (3.68 E-05 lb RSC/Mlb coke) is stated as a function of the coke burn rate. Baseline coke burn rates in turn were calculated as a function of the ratio of the actual charge rate to the maximum charge rate.

2001 H_2S/RSC emissions = [3.68 E-05 lb H_2S/RSC /Mlb coke][15839 MBbl/yr/20884 MBbl/year][412596 Mlb/year][1 ton/2000 lb]
= 5.76 E-03 TPY
2002 H_2S/RSC emissions= [3.68 E-05 lb H_2S/RSC /Mlb coke][16248 MBbl/yr/20884 MBbl/year][412596 Mlb/year][1 ton/2000 lb]
= 5.91 E-03 TPY

PTE H_2S/RSC = [3.68 E-05 lb H_2S/RSC /Mlb coke][412596 Mlb/year][1 ton/2000 lb]
= 7.59 E-03 TPY

Compliance Methodology:

The draft permit will include the following conditions[34]:

FCU emissions shall not exceed:

[34] TPY is defined as "tons per rolling twelve months"

- SO_2: 25 ppmvd @ 0 % O_2 on a 365 day rolling average, 50 ppmvd @ 0 % O_2 on a 7 day rolling average and 174 TPY.
- NO_x: 40 % reduction across the SNCR, stack exit concentration of 78 ppmvd @ 3 % O_2 on an hourly basis and 457 TPY
- TSP (filterable): 206.3 TPY
- H_2SO_4: 40 % reduction across the Belco pre-scrubber and 252.3 TPY
- PM_{10}: 458.5 TPY (inclusive of the H_2SO_4)
- CO: 416 TPY. The Company may apply for an alternate emission limit based on stack test conducted under representative operating conditions.
- VOC as CH_4: 43.8 TPY. The Company may apply for an alternate emission limit based on stack test conducted under representative operating conditions.
- Pb: 4.37 E-04 lb/Mlb coke burn and 9.0 E-02 TPY
- H_2S/RSC: 3.68 E-05 lb/Mlb coke burn and 7.6 E-03 TPY
- NH_3: 8.8 TPY
- HAPs (as Ni)[35]: Combined HAP emissions from the FCU and FCCU: 0.029 lb/hour or 1 lb of PM per 1000 lb of coke burn combined from the FCU and FCCU.
- The FCU throughput shall not exceed 20,884 Mbbl and the coke burn rate shall not exceed 412,596 Mlb, both on a rolling 365 day basis.

SNCR optimization provisions:
The following optimization provisions are incorporated in the permit:

- Premcor shall begin a six-month study to optimize the performance of the SNCR systems ("Optimization Study") to minimize NOx emissions from the FCU. This optimization study shall commence by no later than February 28, 2006, or 3 months after the installation and start-up of the SNCR systems, whichever is earlier.
- Premcor shall submit a protocol for the Optimization Study to the Department that includes a consideration of the operating parameters identified in Attachment 1 of the Consent Decree. As part of the Optimization Study, Premcor shall evaluate the effect of the operating parameters identified in Attachment 1 and shall monitor NOx emissions and the operating parameters to identify optimum operating levels for the parameters that minimize the NOx emissions.
- Premcor shall submit the results of the optimization study to the Department in a written report no later than sixty (60) days after the completion of the study. The report shall identify the relevant operating parameters and their levels that result in the minimization of NOx emissions from the FCU.

[35] See discussion under applicability of 40 CFR 63, subpart UUU.

- As required in Paragraph 13 (j) of the CD, Premcor shall determine the NO_x and O_2 concentrations at the point of emission to the atmosphere by CEMS. As required in Paragraph 13 (j), Premcor shall determine the O_2 concentrations, after combustion in the CO Boiler, by process analyzer(s) calibrated in accordance with the manufacturer's recommendations.
- As part of its optimization study report, Premcor shall propose to the Department short and long term concentration based limits, each at 0% oxygen, and rolling averaging times (i.e., 3-hour, 12-hour, or 24-hour for short term rolling averages and 365-day for a long term rolling average) for the FCU NOx emissions, for optimized operation of the control system consistent with the provisions of Paragraphs 11 - 14. Premcor shall comply with the limits it proposes beginning immediately upon submission of its optimization study report to the Department until such time as Premcor is required to comply with the emissions limits set by the Department, pursuant to Paragraphs 16 and 17 of the CD.
- The Department will use the CEMS data collected during the optimization study and all other available and relevant information to establish limits for NOx emissions from the FCU. The Department may establish NOx concentration limits based on a short term (e.g., 3-hour) rolling average and a long term (i.e., 365-day) rolling average, each at 0% oxygen. The Department will determine the NOx concentration limits and averaging times for the FCU based on the level of performance during the optimization study, a reasonable certainty of compliance, and any other available pertinent information.
- The Department will notify Premcor of its determination of NOx concentration limits and averaging times for each unit, and Premcor shall immediately, or within 30 days if EPA's NOx concentration limit is different from Premcor's proposed limit, operate its SNCR systems at the FCU so as to comply with the established emissions limits.

Monitoring/Testing:

- SO_2: Compliance shall be based on CEMS. The CEMS shall be installed and certified by satisfying the requirements of Performance Specifications No. 2 in Appendix "B" of 40 CFR part 60. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR part 60.
- NO_x: Compliance shall be based on CEMS. The CEMS shall be installed before and after the SNCR system and certified by satisfying the requirements of the applicable Performance Specifications in Appendix "A" of 40 CFR part 75. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "B" of 40 CFR part 75.
- TSP (filterable): Compliance shall be based on an initial Reference Method 5 testing in Appendix "A" of 40 CFR part 60, and annually thereafter.

- H_2SO_4: Compliance shall be based on an initial Reference Method 8 testing in Appendix "A" of 40 CFR part 60, and annually thereafter.
- PM_{10}: Compliance shall be based on an initial Reference Method 201/202 testing in Appendix "M" of 40 CFR part 51, and annually thereafter
- CO: Compliance shall be based on CEMS. The CEMS shall be installed and certified by satisfying the requirements of Performance Specifications No. 4 in Appendix "B" of 40 CFR part 60. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR part 60.
- VOC as CH_4: Compliance shall be based on an initial Reference Method 18 testing in Appendix "A" of 40 CFR part 60, and annually thereafter.
- Pb: Compliance shall be based on an initial Reference Method 12 testing in Appendix "A" of 40 CFR part 60. Future compliance shall be based on the stack test based emission factor in terms of lb/Mlb coke burn rate. The Department reserves the right to require more frequent testing if warranted.
- H_2S/RSC: Compliance shall be based on an initial Reference Method 15 testing in Appendix "A" of 40 CFR part 60. Future compliance shall be based on the stack test based emission factor in terms of lb/Mlb coke burn rate. The Department reserves the right to require more frequent testing if warranted.
- NH_3: Compliance shall be based on a Department approved stack test.
- All monitor certifications shall be conducted within 60 days of the unit attaining maximum production but not later than 180 days after unit start up. A "Source Sampling Guidelines and Preliminary Survey Form" must be submitted and found acceptable to the Department at least thirty (30) days prior to the performance testing. Results of the Performance Specification testing shall be submitted to the Department, in triplicate, within 90 days after completion of the testing.

Recordkeeping:

The Company shall maintain records of CEMS data, stack test results, the daily COB fuel usage, rolling 365 day coke burn rate and FCU throughput.

Reporting:

Quarterly reports for the preceding quarter shall be submitted to the Department by January 31, April 30, July 31 and October 31 of each calendar year with the following information:

- A summary of all excess emissions for the quarter;
- CEMS report to include system calibration and audit results, the actual daily data capture for the period and details of out of control periods
- Exceedances of the rolling 365 day limits of FCU throughput and coke burn rates.

Regulation No. 3 – Ambient Air Quality Standards:

Section 2.1 of this regulation states:
No person shall cause the Air Quality Standards specified in this Regulation to be exceeded.

There are two changes associated with the PCUP that could potentially impact the air quality standards in this regulation.

- First, as a result of the PCUP the SO_2 content of the flue gas at the inlet to the control device will increase from the presently permitted level of 4,450 lb/hour to 7,000 lb/hour. Under normal operation with the flue gas routed through the WGS, the majority of the SO_2 will be captured. However, during periods of upset operations that require the WGS to be bypassed the pollutant will be emitted uncontrolled to the atmosphere. Premcor's modeling exercise has not evaluated the impacts of these uncontrolled emissions on ambient air quality. AQM ran the Industrial Source Complex Short Term (ISCST3 version 02035) model with the 5 year meteorological data supplied by Premcor for uncontrolled emissions using the following stack parameters:

  Diameter: 10 feet
  Height: 240 feet
  Exit temp. 650 deg F
  Exit velocity 104 feet/sec
  Flow: 487548 acfm

  Table 4 summarizes the AQM's modeled results.

  Table 4: Model Results of Uncontrolled FCU SO_2 Emissions

Averaging Time	Standard	NAAQS ($\mu g/m^3$)	Maximum value[36] ($\mu g/m^3$)	Maximum fenceline concentration ($\mu g/m^3$)
3 hour	Secondary	1300	3045	925
24 hour	Primary	365	1069	260
Annual	Primary	80	119	37

  During technical discussions with AQM the Company proposed immediately reducing the FCU throughput to a level that will restrict the unit's SO_2 emission rate the pre-PCUP

[36] The maximum modeled concentrations were located within the property lines of the facility east of Route 9 near the marketing terminal.

emission rate of 4,450 lb/hour during periods when the WGS has to be bypassed. When the WGS is bypassed, the flue gas will be emitted through the existing metal stack which is equipped with concentration and flow CEMS. AQM finds Premcor's proposal to be acceptable.

- Second, the PCUP project will result in an increase in the daily coke production from 1,880 tons (annual average)[37] to about 2450 tons. At the current operating level, the facility has monitored and recorded 23 days of violation of the Delaware Secondary 24 hour Ambient Air Quality Standard for Total Suspended Particulate Matter of 150 $\mu g/m^3$. AQM is entering into a separate settlement agreement with Premcor to resolve this issue.

Compliance Methodology:

Compliance shall be based on CEMS.
The hourly mass emission rate shall be calculated from the following equation:

SO_2 (lb/hour) = $[C_{(ppmw)} / [1- B_{ws}]][1.66 \text{ E-7 lb } SO_2/\text{dscf.ppm}][Q_{i,w}][1 - B_{ws}]$

where:
$C_{(ppmw)}$ = wet concentration as measured by CEMS
B_{ws} = moisture mole fraction
1.66 E -7 is the conversion factor to convert ppm to lb SO_2/dscf
$Q_{i,w}$ = wet flow

Monitoring/Testing:

The SO_2 CEMS shall be installed and certified by satisfying the requirements of Performance Specifications No. 2 in Appendix "B" of 40 CFR part 60. The flow CEMS shall be installed and certified by satisfying the requirements 40 CFR part 75, Appendix "A". The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR part 60.

Recordkeeping:

- The Company shall The Company shall maintain records of CEMS data, calibration and audit results

[37] See Star Enterprise: Repowering Project Application dated May 27, 1997; Coke Handling and Storage Operations, Input Table.

- All periods of FCU WGS being bypassed and the hourly SO_2 emissions during those periods

Reporting:

Quarterly reports for the preceding quarter shall be submitted to the Department by January 31, April 30, July 31 and October 31 of each calendar year with the following information:

- A summary of all periods when the FCU WGS has been bypassed
- Actual hourly SO_2 emissions during periods of FCU WGS bypassed
- CEMS report to include system calibration and audit results, the actual daily data capture during periods of FCU WGS bypassed

Regulation No. 5 – Particulate Emissions from Industrial Process Operations:

Section 5.2 of this regulation states:
No person shall cause or allow particulate emissions from fluid coking operations into the atmosphere in excess of the quantities as indicated in Table 4.

Compliance Methodology:

As explained above, all particulate emissions (including H_2SO_4) are considered to be PM_{10}. The PTE for PM_{10} is 458.5 TPY or 104.7 lb/hour at a feed rate of 57,216 Bbl/day design fresh feed rate. On the other hand, the design maximum feed rate of 57,216 Bbl/day corresponds to an emission rate of the emission limit of 168 lb/hour using Table 4 of Regulation 5. Therefore, compliance with this regulation is based on compliance with the emission limit in the permit (see discussion under Regulation No. 2).

Monitoring/Testing, Recordkeeping and Reporting:

None in addition to those discussed under regulation No. 2.

Regulation No. 8 – Sulfur Dioxide Emissions From Fuel Burning Equipment:

Section 2.1 states:
Except as provided in Section 2.2, no person shall offer for sale, sell, deliver, or purchase any fuel having a sulfur content greater than one (1.0) percent by weight when such fuel is intended for use in any fuel burning equipment in New Castle County. No person shall use any fuel

having a sulfur content greater than one (1.0) percent by weight in any fuel burning equipment in New Castle County.

This regulation applies only to the FCU COB which meets the definition of fuel burning equipment.

Compliance Methodology:

The FCU COB combusts desulfurized RFG and process offgas containing CO and sulfur species that result in 7,000 ppmvd SO_2 loading to the WGS. The flue gases are discharged to meet the CD mandated emission level of 25 ppmvd at 0 % O_2 on a 365 day rolling average basis and 50 ppmvd at 0 % O_2 on a 7 day rolling average basis. Both these limits are several orders of magnitude more stringent than the corresponding regulatory limit of 1 % S in fuel. Therefore, no additional discussion is presented here.

Regulation No. 8 – Emissions of Sulfur Dioxide From Industrial Operations:

Section 1.1 of this regulation states:
The emission of sulfur dioxide from process operations shall be controlled to a limit that shall meet the ambient air quality requirements.

Compliance Methodology:

The Company has modeled emissions from the refinery using the ISC3 ST (version 02035) to demonstrate no adverse impacts to ambient air quality. However, the Company has not modeled impacts during atypical operations which frequently result in outages of the COB which in turn causes bypassing the WGS. [See discussion under Regulation No. 3]

Regulation No. 11 – Carbon Monoxide Emissions From Industrial Process Operations – NC County

Section 2.1 of this regulation states:
In New Castle County, no person shall cause or allow the emission of carbon monoxide from any catalytic regeneration of a petroleum cracking system, petroleum fluid coker, or other petroleum process into the atmosphere, unless the carbon monoxide is burned at 1300 F for 0.3 seconds o or greater in a direct-flame afterburner or boiler, or is controlled by an equivalent technique.

Compliance Methodology:

CO is combusted in the furnace of the FCU COB. The design operating temperature in the FCU COB at the boiler nose is 1750 deg. F. With a firebox volume of 9,451 ft^3, the average residence time of the flue gas is 2.19 sec.[38]

Monitoring/Testing:

The Company shall monitor the FCU COB firebox temperature continuously.

Recordkeeping:

The company shall maintain records of the firebox temperature for 5 years.

Reporting:

The Company shall submit quarterly reports of all periods when the firebox temperature fell below 1300 deg F. Each report shall be submitted within 30 days of the end of the quarter.

Regulation No. 14 – Visible Emissions:

Section 2.1 of this regulation states:
No person shall cause or allow the emission of visible air contaminants and/or smoke from a stationary or mobile source, the shade or appearance of which is greater than twenty (20%) percent opacity for an aggregate of more than three (3) minutes in any one (1) hour or more than fifteen (15) minutes in any twenty-four (24) hour period.

Compliance Methodology:

As observed from the material balance the WGS stack will have a significant moisture content (about 27 mole %) that will make the use of a continuous opacity monitoring system impractical. Therefore, evaluations of visible emissions will have to be made at a point where the condensed water is no longer visible in accordance with 40 CFR part 60, Appendix "A", Reference Method 9, Section 2.3.1.

The Company shall maintain a log of daily qualitative observations using Reference Method 22 in Appendix "A" of 40 CFR part 60. In the event visible emissions are observed by reference

[38] T_r = 9451 Ft^3/[40262 lb.mole/hour][385.5 DSCF/lb.mole][2.77 E-04 hour/sec]
= 2.19 sec.

Method 22, the Company shall conduct a visible emissions evaluation using the procedures described in Regulation 20, section 1.5 (c). At all other times, compliance shall be based on the proper operation of the emissions unit and record keeping.

Monitoring/Testing:

Conduct visual observations at fifteen-second intervals for a period of not less than one hour except that the observations may be discontinued whenever a violation of the standard is recorded. The additional procedures, qualification and testing used for visually determining the opacity shall be those specified in Section 2 and 3 (except for Section 2.5 and the second sentence of Section 2.4) of reference Method 9 set forth in Appendix A, 40 CFR Part 60, revised July 1, 1982.

Recordkeeping:

Observation records shall be maintained on site.
Records of all maintenance performed on applicable units shall be maintained.

Reporting:

The Company shall submit quarterly reports indicating the duration and magnitude of all periods of excess opacity.

Regulation No. 17 – Source Monitoring, Recordkeeping and Reporting:

Section 2.1 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, install, maintain, and use emission monitoring devices, keep records, and make periodic reports to the Department on the nature and amount of emissions from such source. The Department shall make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, sample the emissions of, or fuel used by, that source, maintain records and submit reports to the Department on the results of such sampling. The Department may make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
The Department may conduct tests of emissions from or fuel used by any air contaminant source. Upon written request of the Department, the owner or operator of the air contaminant source shall provide necessary holes in stacks or ducts, and such other safe and proper sampling and testing facilities, exclusive of instruments and sampling devices, if any are necessary, for proper determinations of the emission of air contaminants. The Department shall have access to and use of monitoring, record-keeping and reporting required by Federal Regulations relating to emissions of air contaminants. The Department may make such data available to the public as reported or received and as correlated with any applicable emissions standards or limitations.

Compliance Methodology:

Compliance shall be based on the monitoring/testing requirements

Monitoring/Testing, Recordkeeping and Reporting:

None in addition to those included under the applicability of Regulation No. 2.

Regulation No. 19 – Control of Odorous Air Contaminants

This regulation is applicable to all affected emissions units in the refinery. Therefore, it's applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 20 & 40 CFR Part 60, Subpart J – New Source Performance Standards

Section 104 (a) of 40 CFR part 60, Subpart "J" is an applicable requirement for the FCU COB and the back up incinerator. This requirement restricts the H_2S content in the RFG combusted to less than 162 ppmvd. The H_2S concentration in the RFG is already monitored by CEMS and thus creates no new requirement. Therefore, no additional discussion is presented here.

Regulation No. 24 – Control of Volatile Organic Compound Emissions

Sections 28 and 29 are applicable to the FCU and prescribe the same requirements as described under the heading "Crude Unit". Therefore, no additional discussion is presented here.

40 CFR 60, Subparts GGG and VV:

Both these regulations are applicable to the FCU and prescribe the same requirements as described under the heading "Crude Unit". Therefore, no additional discussion is presented here.

40 CFR 63, Subpart CC – NESHAP for Petroleum Refineries

This regulation is applicable to the FCU and prescribe the same requirements as described under the heading "Crude Unit". Therefore, no additional discussion is presented here.

Consent Decree LDAR Requirements:

The CD LDAR requirements are applicable to the FCU and prescribe the same requirements as described under the heading "Crude Unit". Therefore, no additional discussion is presented here.

Regulation No. 39 – Nitrogen Oxides Budget Trading Program:

Section 2 of Regulation 39 states:

a. *Each NO_X Budget unit shall hold in its compliance account and/or its overdraft account, as of the NO_X allowance transfer deadline of each control period, a quantity of NO_X allowances available for deduction that is equal to or greater than the total NO_X emissions from that NO_X Budget unit for that control period.*
b. *Each NO_X Budget unit shall be subject to the requirements of Section 2(a) of this regulation starting on the later of May 1, 2003 or the date the unit commences operation.*

The FCU COB has a rated heat input of 674 mmBtu/hour. Therefore, it is an affected unit under the NO_x Budget Trading Program.

Compliance Determination Methodology for Regulation No. 39[39]:

Compliance is based on operating a certified CEMS and the recordkeeping and reporting requirements.

Monitoring & Testing:

[39] The requirements of Regulation 39 are unaffected by the PCUP. The discussion on the applicability of this regulation is included for completeness. Since all the Regulation 39 requirements are already included in the NO_x Budget Permit, these requirements are not being repeated in this permitting action.

1. The Company and, to the extent applicable, the NOx authorized account representative of each NOx Budget source and each NO_X Budget unit at the source shall comply with the monitoring requirements of Regulation No. 39 § 8.
2. The emissions measurements recorded and reported in accordance with Regulation No. 39 § 8 shall be used to determine compliance by the unit with the NOx Budget emissions limitation under paragraph (c).

Record Keeping and Reporting:

Unless otherwise provided, the owners and operators of the NOx Budget source and each NOx Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

a. The account certificate of representation under Regulation No. 39 § 6 and all documents that demonstrate the truth of the statements in the account certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new account certificate of representation under Regulation No. 39 § 6 changing the NOx authorized account representative.
b. All emissions monitoring information, in accordance with Regulation No. 39 § 8; provided that to the extent that Regulation No. 39 § 5 provides for a 3 year period for record keeping, the 3 year period shall apply.
c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the NOx Budget Trading Program.
d. Copies of all documents used to complete a NOx Budget permit application and any other submission under the NOx Budget Trading Program or to demonstrate compliance with the requirements of the NOx Budget Trading Program.
e. Records demonstrating that any unit exempted under Regulation No. 39 § 3(b) of this regulation is retired. The owner(s) or operator(s) of that unit bears the burden of proof that the unit is retired.
f. The NOx authorized account representative of a NOx Budget source and each NOx Budget unit at the source shall submit the reports and compliance certifications required under the NOx Budget Trading Program, including those under Regulation No. 39 § 7, 8, and 11.
g. Each document submitted to the Department and the Administrator pursuant to this permit shall be signed and certified by the Authorized Account Representative and shall contain the following language:

"I am authorized to make this submission on behalf of the owners and operators of the NOx Budget sources or NOx Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

40 CFR part 63 Subpart UUU –- NESHAP From Petroleum Refineries – Catalytic Cracking Units, Catalytic Reforming Units and Sulfur Plants

This regulation is not applicable to the FCU. However it is applicable to the FCCU and is being discussed here because Premcor's compliance strategy with respect to the FCCU's particulate HAP emissions is to route a slurry recycle stream containing these HAPS to the FCU for control at that unit which is presently equipped with an electrostatic precipitator. FCCU HAP emissions have to be controlled to meet either Section 63.1562 (a)(1)(i) or Section 63.1562 (a)(1)(ii) by no later than April 11, 2005.

Section 63.1562 (a)(1)(i) requires that FCCU PM emissions shall not exceed 1 lb/1000 lb of coke burn in the FCCU regenerator. Alternately, Section 63.1562 (a)(1)(i) requires that FCCU Ni emissions shall not exceed 0.029 lb/hour.

Stack testing has shown the FCCU Ni emission to be 0.145 lb/hour. The WGS, when installed and operating, is expected to meet the requirements of either Sections 63.1562 (a)(1)(i) or 63.1562(a)(1)(ii). However, the WGSs will not be installed before June 30, 2006 on the FCU and December 31, 2006 on the FCCU. Therefore, in the interim period, i.e., between April 11, 2005 (the MACT compliance deadline for the FCCU) and December 31, 2006, Premcor's strategy is to route the slurry recycle stream containing these HAPS to the FCU. AQM finds this proposal to be acceptable subject to the following conditions:

- The slurry recycle stream shall be returned to the FCCU after December 31, 2006
  And
- Combined PM emissions from the FCU and FCCU shall not exceed either 1 lb of PM per 1000 lb of combined coke burn.

  Or

- Combined nickel emissions shall not exceed 0.029 lb Ni/hour from the FCU and FCCU.

Compliance Methodology:

Compliance shall be based on the monitoring/testing requirements.

Monitoring/Testing:

- In the interim period from April 11, 2005 through December 31, 2006, the Company shall demonstrate compliance with the requirement of 1 lb of PM per 1000 lb of combined coke burn in accordance with the provisions in Section 60.106 (b)(1). Alternately, the Company may demonstrate compliance with the combined Ni emissions of 0.029 lb Ni/hour from the FCU and FCCU in accordance with Reference Method 29 of 40 CFR 60, Appendix "A".
- Compliance stack testing shall be carried out simultaneously on the FCU and FCCU stacks.
- Annual stack testing on the FCCU will be required to demonstrate compliance with the emission limitation.

Recordkeeping:

The Company shall maintain the following records:
- Stack test results
- Hourly FCCU and FCU Coke burn rates

Reporting;

The Company shall submit the results of the annual compliance test report within 90 days of completion of the test.

Sulfur Recovery Area (SRA)(Unit 28):

Regulation No. 2 - Permits:
Section 2.1 (c) of this Regulation states:
Except as exempted in Section 2.2, no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department or, if eligible, prior to submitting to the Department a completed registration form for equipment, a facility or an air contaminant control device that is not subject to Section

2.1(a) or 2.1(b), the person shall submit to the Department an application for a permit pursuant to Section 11of this regulation.

Section 11.6 of this Regulation states:
No permit shall be issued by the Department unless the applicant shows to the satisfaction of the Department that the equipment, facility, or air contaminant control device is designed to operate or is operating without causing a violation of the State Implementation Plan, or any rule or regulation of the Department, and without interfering with the attainment or maintenance of National and State ambient air quality standards, and without endangering the health, safety, and welfare of the people of the State of Delaware. The Department may, from time to time, issue or accept criteria for the guidance of applicants indicating the technical specifications which it deems will comply with the performance standards referenced herein.

Furthermore, Section 11.8 states:
The following emission rates and/or standards for each air contaminant emitted from any equipment, facility or air contaminant control device shall be specified in each permit issued pursuant to this regulation:

*a. The rate and/or standard established and/or relied upon in the State Implementation Plan (SIP) to include the State of Delaware "**Regulations Governing the Control of Air Pollution**" and regulations promulgated pursuant to Section 111 and Section 112 of the Clean Air Act (CAA); and*

b. The rate that was shown under Section 11.6 as not interfering with the attainment and maintenance of any National and State ambient air quality standard, and not endangering the health, safety, and welfare of the people of the State of Delaware; or

c. The rate requested by the applicant. In no case shall this rate be greater than the potential to emit of the equipment, facility, or air contaminant control device; and in no case shall this rate be less stringent than the rate specified in Section 11.8(a) and (b) of this regulation.

This regulation is applicable to the SRA since changes involve alteration of equipment that emits air contaminants. Premcor's application has included an emissions comparison that compares the current allowable emissions to the future potential emissions after completion of the PCUP. The application states that actual emissions have been set equal to current allowable emissions because the unit has not yet begun normal operations following the construction of modifications to the SRA which were permitted in 2002.[40] AQM disagreed with Premcor on the comparison of

[40] The application in Section E-5 does not provide an explanation as to why the SRA should be considered as not having begun normal operations. This issue was brought up during technical discussions with the Company and AQM was informed that 2 years of representative operating

"current allowable" emissions to the "future potential" emissions". Instead, AQM believes it is appropriate to make this comparison on a "current actual" to "future potential" basis using 12 months operating data following the completion of modification of the SRA to allow for the sulfur pit degassing project. Therefore, Table 4 shows the SRA emissions comparison between the average baseline emissions of 2003-2004 and the PTEs after implementation of the PCUP.

Table 5: SRA Emissions Comparison (TPY)

Pollutant	Current Allowable	Average (July 03 to June 04)[41]	PTE	Net Δ[42]
SO_2	375.4	156.5	672.1	515.6
NO_x	30.7	33.4	51.9	21.2
TSP	6.8	6.1	22.3	16.2
H_2SO_4	5.9	6.6	11.6	5.7
PM_{10}	6.8	6.1	10.8	4.7
CO	7.7	8.5	26	18.3
VOC	0.7	0.7	1.3	0.6
Pb	1.1 E-04	1.1 E-04	1.8 E-04	7.0 E-05
TRS/RSC	8.0	7.0	12.7	5.7
H_2S	8.0	7.0	12.7	5.7

The "current actual" emissions were calculated as follows:
SO_2 baseline emissions obtained from CEMS data
NO_x baseline emissions = [242.76 mmBtu-ton/lb-year][0.14 lb/mmBtu[43]] = 33.4 TPY.
TSP and PM_{10} baseline emissions = [242.76 mmBtu-ton/lb-year][0.025 lb/mmBtu[44]] = 6.1 TPY
H_2SO_4 baseline emissions = [242.76 mmBtu-ton/lb-year][0.027 lb/mmBtu] = 6.6 TPY

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data is not yet available after the sulfur pit degassing project was completed in the summer of 2003.

[41] The "current actual" emissions were computed from the spreadsheet attachment to e-mail from Jim Fedena to Ravi Rangan dated August 12, 2004. Baseline emissions were calculated from the spreadsheet using the 12 month (July 2003 through June 2004) average values for the following parameters: HV = 1,166 Btu/dscf and fuel consumption of 34.7 mmSCF/month resulting in a factor of 242.76 mmBtu-ton/lb-year.

[42] In calculating the delta values, the "current allowable" has been used only where it is less than the "current actual".

[43] NO_x emission factor of 0.14 lb/mmBtu from **Permit: APC-90/0264-CONSTRUCTION(Amendment 2)(NSPS)** dated August 5, 2002.

[44] PM_{10} emission factor of 0.025 lb/mmBtu from **Permit: APC-90/0264-CONSTRUCTION(Amendment 2)(NSPS)** dated August 5, 2002.

CO baseline emissions = [242.76 mmBtu-ton/lb-year][0.035 lb/mmBtu[45]] = 8.5 TPY
VOC baseline emissions = [242.76 mmBtu-ton/lb-year][0.003 lb/mmBtu[46]] = 0.7 TPY
Pb baseline emissions = [242.76 mmBtu-ton/lb-year][4.2 E-07 lb/mmBtu] = 1.1 E-04 TPY
H_2S/RSC baseline emissions = [242.76 mmBtu-ton/lb-year][2.9 E-02 lb/mmBtu] = 7.0 TPY

The "future potential" emissions were calculated as follows based on the assumptions listed below:
Assumptions: SRA design recovery efficiency of 99.9 % yielding 822 LTPD ESPC and annual fuel usage of 865,000 mmBtu.

Thus, SO_2 PTE = [822 LTPD S][1 – 99.9/100][2240 lb S/LT S][1 day/24 hours][64 lb SO_2/lb mole S][1 lb mole S/32 lb S]
= 153.4 lb/hour
= 672 TPY

NO_x PTE = [0.12 lb NO_x/mmBtu][865,000 mmBtu/year][5 E-04 ton/lb]
= 51.9 TPY

TSP = PM_{10} PTE = [0.025 lb PM_{10}/mmBtu[47]][865,000 mmBtu/year][5 E-04 ton/lb]
= 10.8 TPY

CO PTE = [0.06 lb CO/mmBtu[48]][865,000 mmBtu/year][5 E-04 ton/lb]

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[45] CO emission factor of 0.035 lb/mmBtu from **Permit: APC-90/0264-CONSTRUCTION(Amendment 2)(NSPS)** dated August 5, 2002.
[46] VOC emission factor of 0.003 lb/mmBtu from **Permit: APC-90/0264-CONSTRUCTION(Amendment 2)(NSPS)** dated August 5, 2002.
[47] Premcor has asked for a revision of the PM_{10} emission factor from the existing level of 0.025 lb/mmBtu to 0.052 lb/mmBtu. AQM notes that Premcor has not been able to demonstrate compliance with the existing PM_{10} emission limit of 0.025 lb/mmBtu. AQM is not revising the emission limit to 0.052 lb PM_{10}/mmBtu because Premcor has not taken any measures to find the cause of non-compliance. AQM notes that the PM_{10} emission limit has already been revised once from the previously permitted level of 0.003 lb/mmBtu because of a inherent bias in the test methodology. However, AQM does not find it to be in accordance with good air pollution control practices, if the limit is revised again without undertaking any diagnostic measures to ascertain the causes for the non-compliance.
[48] The application indicates the PTE for CO emissions to be 105 TPY based on an emission factor of 0.24 lb/mmBtu, which in turn is attributed to a CO exit concentration of 100 ppmvd (See SRP emissions spreadsheet on page E-24 of Appendix E). The Company has indicated a CO concentration of 100 ppmvd is reasonably achievable as borne out by stack testing. AQM

= 26 TPY

VOC PTE = [0.003 lb VOC/mmBtu][865,000 mmBtu/year][5 E-04 ton/lb]
= 1.3 TPY

H_2SO_4 PTE = [0.027 lb H_2SO_4/mmBtu][865,000 mmBtu/year][5 E-04 ton/lb]
= 11.6 TPY

Pb PTE = [4.2 E-07 lb Pb/mmBtu][865,000 mmBtu/year][5 E-04 ton/lb]
= 1.8 E-04 TPY

H_2S/RSC PTE = [2.9 E-02 lb H_2S/RSC/mmBtu][865,000 mmBtu/year][5 E-04 ton/lb]
= 12.7 TPY

Compliance Methodology:

The draft permit will include the following conditions[49]:

Unless specified all mass emissions shall apply to SCOT I and SCOT II combined. The SRA emissions shall not exceed:

- SO_2: 250 ppmvd @ 0 % O_2 in each SCOT stack on a 12 hour rolling average, 153.4 lb/hour on a 24 hour rolling average and 672 TPY
- NO_x: 0.12 lb/mmBtu in each SCOT stack and 51.9 TPY
- PM10: All particulate emissions shall be considered as PM_{10}. PM_{10} emissions shall not exceed 0.025 lb/mmBtu in each SCOT stack and 10.8 TPY
- H_2SO_4:1.6 TPY
- CO: 0.06 lb/mmBtu in each SCOT stack and 26 TPY
- VOC as CH_4: 0.003 lb/mmBtu in each SCOT stack and 1.3 TPY
- Pb: 1.8 E -04 TPY

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reviewed previous stack test results from 2002 and found both SCOT units to be operating in compliance at levels below 10 ppmvd. However, because higher CO concentrations are likely to result when the incinerators are tuned to minimize NO_x emissions, AQM finds the requested 100 ppmvd CO concentration to be a reasonable basis. Since the actual stack oxygen concentration has not been specified in the application AQM calculated a CO emission factor based on a dry oxygen free fuel factor of 8700 dscf/mmBtu to be 0.06 lb/mmBtu, i.e., [100 SCF CO/10^6 SCF flue gas][28 lb CO/lb.mole CO][1 lb mole CO/385.3 SCF CO][8700 DSCF flue gas/mmBtu].

[49] TPY is defined as "tons per rolling twelve months"

- H_2S/RSC: 12.7 TPY

Additionally, the existing Regulation 2 permit specifies operational restrictions on the SRA to ensure that PSD applicability under New Source Review requirements are not triggered.
The PCUP will increase the sulfur plant loading from its present level because of the following reasons:

- Acid gas removed from the FCU and FCCU flue gases will be routed to the SRA;
- The crude unit will be able to operate at a new throughput level of 185 MBPD;
- The FCU will be able to operate at it's design capacity of 57 MBPD after the WGS is installed .

As a result of the PCUP, the SRA capacity will have to increase to accommodate the additional sulfur loading. This will be accomplished by operating the Claus units under 58 % oxygen enhancement. The oxygen enhanced mode of operation will revise the SRA capacity restrictions as shown below:

- When both Claus trains and SCOT units are in operation, the SRP shall not be operated at an ESPC greater than 822 LTPD on a 12 month rolling average
- When Claus train I (SRU I) and SCOT II is shutdown, Claus train II and SCOT I unit shall not operate at an ESPC greater than 499 LTPD on a 12 month rolling average
- When Claus train II (SRU II) and SCOT I is shutdown, Claus train I and SCOT II unit shall not operate at an ESPC greater than 499 LTPD on a 12 month rolling average

Monitoring/Testing:

- SO_2: Compliance shall be based on CEMS. The CEMS shall be installed and certified by satisfying the requirements of Performance Specifications No. 2 in Appendix "B" of 40 CFR part 60. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR part 60.
- NO_x: Compliance shall be based on annual stack test.
- TSP/PM_{10}: Compliance shall be based on an initial Reference Method 201/202 testing in Appendix "M" of 40 CFR part 51, and annually thereafter.
- H_2SO_4: Compliance shall be based on an initial Reference Method 8 testing in Appendix "A" of 40 CFR part 60, and annually thereafter.
- CO: Compliance shall be based on CEMS. The CEMS shall be installed and certified by satisfying the requirements of Performance Specifications No. 4 in Appendix "B" of 40 CFR part 60. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR part 60.

- VOC as CH_4: Compliance shall be based on an initial Reference Method 18 testing in Appendix "A" of 40 CFR part 60, and annually thereafter.
- Pb: Historic stack testing has adequately demonstrated very low emissions levels of Pb. Therefore, AQM is not requiring any additional testing here.
- H_2S/RSC: Compliance shall be based on an initial Reference Method 15 testing in Appendix "A" of 40 CFR part 60. The Department reserves the right to require more frequent testing if warranted.
- All monitor certifications shall be conducted within 60 days of the unit attaining maximum production but not later than 180 days after unit start up. A "Source Sampling Guidelines and Preliminary Survey Form" must be submitted and found acceptable to the Department at least thirty (30) days prior to the performance testing. Results of the Performance Specification testing shall be submitted to the Department, in triplicate, within 90 days after completion of the testing.

Recordkeeping:

The Company shall maintain records of CEMS data, stack test results, the daily fuel usage, rolling 365 day ESPC for each train, feed rate of each acid gas stream, SCOT recycle rates and the magnitude and durations of acid gas and tail gas flaring incidents.

Reporting:

Quarterly reports for the preceding quarter shall be submitted to the Department by January 31, April 30, July 31 and October 31 of each calendar year with the following information:

- A summary of all excess emissions for the quarter;
- CEMS report to include system calibration and audit results, the actual daily data capture for the period and details of out of control periods
- Exceedances of the rolling 12 month ESPC limits
- Details of magnitude, duration, causes and actions taken during acid and tail gas flaring incidents

Regulation No. 3 – Ambient Air Quality Standards:

This regulation is applicable to all affected emissions units in the refinery. Therefore, it's applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 4 and Regulation No. 5:

In order to be exempt from Regulation 4, the rated heat input must be less than 1 mmBtu/hour. The rated heat input of units 28-H-201 is 44.5 mmBtu/hour, 28-H-802 is 46 mmBtu/hour and unit 28-S-202 is 45 mmBtu/hour. Therefore, the provisions of Regulation No. 4 are applicable requirements. These units are also part of the SRA which is an industrial process operation. Therefore, the provisions of Regulation No. 5 are also applicable.

Compliance Determination Methodology for Regulation No. 4 and 5:

AQM has employed the same annual heat input of 865,000 mmBtu as used in the PTE calculations. The existing Regulation 2 permit established particulate emissions at 0.025 lb/mmBtu and 6.8 tons per rolling twelve months based on a rolling twelve month fuel usage of 440 mmSCF. Premcor has not been able to demonstrate compliance with this emission limit and is seeking to revise this limit to 0.052 lb/mmBtu based on a recent stack test done in July 2003. Premcor asserts this stack test indicated considerable condensable emissions largely composed of sulfates were the cause of non-compliance. AQM's research into particulate emissions from SRA operations indicate condensable sulfate emissions can indeed sometimes lead to higher particulate emissions. However, AQM notes that it has not reviewed Premcor's July 2003 stack test data and analysis. Furthermore, to AQM's knowledge, Premcor has not conducted or evaluated any additional operational changes incorporating good air pollution control practices that will likely result in compliance at a level below that sought at 0.052 lb/mmBtu. Therefore, AQM is incorporating the TPY limit based on the sought emission factor of 0.052 lb/mmBtu with a provision to lower the limit after subsequent stack testing.

The PM_{10} PTE as calculated under the discussion in the applicability of Regulation No. 2 is 22.3 TPY, which translates to 44,600 lb/year. For compliance with the emission standard in Regulation No. 4, the emissions have to be less than 0.3 lb/mmBtu on a 2 hour average. This criterion is met because the annual heat input will be restricted to 865,000 mmBtu,

i.e., PM emissions = [22.3 tons/year][2000 lbs./ton]/[865000 mmBtu/year]
= 0.05 lbs./mmBtu < 0.3 lbs./mmBtu

For verification of compliance with the standard of 0.2 grains/DSCF

PM emissions = [0.05 lbs./mmBtu][865,000 mmBtu/year][7000 grains/SCF] ÷ [(10,557 SCFM)(60 min./hour)(8760 hours/year)]
= 0.055 grains/DSCF < 0.2 grains/DSCF

Monitoring/Testing:

The Company shall conduct a Department approved stack test within 60 days of the unit achieving the maximum production at which the SRA will be operated but not later than 180

days after initial start up and annually thereafter. The Department reserves the right to establish a lower annual limit based on the stack test results.

Recordkeeping:

Stack test results and records documenting the amount of fuel burned in each SRA train.

Reporting:

None in addition to those required for compliance with Regulation No. 2 above.

Regulation No. 8:

Regulation No. 8 stipulates that no person may combust any fuel with a sulfur content greater than 1 percent by weight. Both units combust only RFG that is desulfurized to conform to the NSPS limit of 0.1 grain H_2S/DSCF (See applicability of 40 CFR 60, Subpart "J" below). The NSPS limit of 0.1 grain/DSCF is more stringent than the requirements of Regulation No. 8. Therefore, no additional requirements are proposed here

Regulation No. 9:

Regulation No. 9 requires that the emissions of SO_2 in the tail gases from the SRA be less than 2000 ppmv or that specified in Table 2 of the regulation. This SRA will have a nominal equivalent sulfur production capacity of 822 LTPD after the PCUP is completed. The higher capacity of 556 LTPD corresponds to an SO_2 mass emission rate of 2355 lbs./hour. The proposed permit will restrict the 24 hour rolling average SRA emissions from both SCOT units combined to 153.4 lb/hour. Therefore, no additional requirements are proposed here.

Regulation No. 12:
Section 3.3 b states:
The maximum emission rates for nitrogen oxides from fuel burning equipment with a rated heat input capacity of less than 100 MMBTU/hr shall be as follows:
Less than 50 MMBTU/hr: Shall not exceed those achieved through an annual tune up performed by qualified personnel. The owner or operator shall maintain a log of the tune ups performed on each unit.

As the application indicates, SCOT I was constructed prior to the applicability date of this regulation, i.e., November 15, 1992. However, SCOT II was constructed in 1998 and is thus

subject to this Regulation. AQM believes it is reasonable to require both SCOT units to be tuned up annually.

Compliance Methodology:

The Company shall conduct an annual tune up of each SCOT unit incinerator performed by qualified personnel.

Recordkeeping and Reporting:

The Company shall maintain records of the annual tune ups performed and shall submit an annual report upon the Department's request.

Regulation No. 14:

This regulation establishes visible emission limits at twenty percent (20%) opacity for an aggregate of more than three (3) minutes in any one (1) hour period, or more than fifteen (15) minutes in any twenty-four (24) hour period

Tail gases from sulfur recovery operations have rarely caused opacity problems. Therefore, compliance shall be demonstrated through the proper operation and maintenance of the SRA. In addition, the Company shall conduct qualitative stack observations on a daily basis noting the presence or absence of any visible emissions. In the event any visible emissions are observed, the Company shall conduct a Reference Method 9 visible emissions evaluation.

Regulation No. 17:

This regulation pertains to source monitoring, record keeping and reporting. CEMS will be used to demonstrate compliance with the NSPS SO_2 emission limits of 250 ppmvd at 0 % O_2 and the Regulation No. 2 permit limit of 153.4 lbs./hour on a twenty four hour rolling average (see discussion under Regulation No. 20 below). These requirements are more stringent than the requirements of Regulation No. 17. Therefore, no additional requirements are proposed here.

Regulation No. 19:

This regulation is state enforceable only and is addressed under "Facility Wide Applicable Requirements".

Regulation No. 20 and 40 CFR 60, Subpart "J":

The requirements of Regulation No. 20, Section 11 incorporate by reference 40 CFR 60, Subpart "J" - the federal NSPS for petroleum refineries. The NSPS standard has the following requirements:

- Limits the maximum hydrogen sulfide (H_2S) content in refinery fuel gas to 0.1 grain/DSCF (230 mg/DSCM) on a three hour rolling average basis.
- Limits the SO_2 emissions in the tail gases to 250 ppmvd at zero % O_2.

In addition, the proposed permit also incorporates the current Reg. 2 permit provisions for emission limitations during periods of start up and shut downs.[50]

[50] **SULFUR RECOVERY AREA - START UP AND SHUT DOWN SCENARIOS**

The following start up and shut down scenarios are hereby incorporated:

SCENARIO 1: Planned SCOT I and/or SCOT II Shut Down:
When either SCOT unit shut down is **planned**, the stand by SCOT unit shall be brought to a state of readiness for operation before the operating SCOT unit is taken out of service. Within two (2) hours after the operating SCOT unit is shutdown, all of the tailgases shall be treated in the standby SCOT unit. The maximum amount of SO_2 that shall be emitted during this 2-hour period shall not exceed 4.2 tons.

SCENARIO 2:Melting and Burn-out After Planned Shut Down of SRU I and SRU II:
After SRU I or SRU II has been shut down, the off gases resulting from the residual sulfur melting and burn-out shall be incinerated before exiting the stack. The melting and burn-out procedure shall not exceed seven (7) days. The maximum amount of SO_2 resulting from this procedure shall not exceed fifteen (15) tons per day.

SCENARIO 3: Planned Start Up of SRU I and SRU II:
When SRU I or SRU II is returned to service the tail gas from the unit being returned to service shall be incinerated until the proper ratio of H_2S:SO_2 in the acid feed gas is attained. This ratio shall be established within two (2) hours at which time the tail gas shall be fed to either SCOT Unit. During this start-up period the emissions of SO_2 shall not exceed 4 tons per start-up event for either SRU.

SCENARIO 4: Burnout of SCOT Reactor During Shutdown of Either SCOT Unit:

Compliance Determination Methodology for Regulation No. 20 and 40 CFR 60, Subpart "J":

Compliance will be based on CEMS.

Recordkeeping and Reporting Requirements:

None in addition to those required under Regulation No. 2 above.

After the planned shut down of either SCOT I or II, in order to safe the catalyst it can be slowly burned free of sulfur. SO_2 emissions from this operation shall not exceed 9.6 tons, over a six day period.

Monitoring and Reporting Requirements:
During start-up and shut-down periods of incineration, ambient air monitoring data for the affected period shall be collected and submitted to the Department daily. Corrective action shall be taken if there is any indication that an exceedance of ambient air standards might take place. At the Department's request copies of available air monitoring data shall be furnished to the Air Quality Management Section.

Package Boilers A & B:

Regulation No. 2 - Permits:

Section 2.1 (c) of this Regulation states:
Except as exempted in Section 2.2, no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department or, if eligible, prior to submitting to the Department a completed registration form for equipment, a facility or an air contaminant control device that is not subject to Section 2.1(a) or 2.1(b), the person shall submit to the Department an application for a permit pursuant to Section 11of this regulation.

Section 11.6 of this Regulation states:
No permit shall be issued by the Department unless the applicant shows to the satisfaction of the Department that the equipment, facility, or air contaminant control device is designed to operate or is operating without causing a violation of the State Implementation Plan, or any rule or regulation of the Department, and without interfering with the attainment or maintenance of National and State ambient air quality standards, and without endangering the health, safety, and welfare of the people of the State of Delaware. The Department may, from time to time, issue or accept criteria for the guidance of applicants indicating the technical specifications which it deems will comply with the performance standards referenced herein.

Furthermore, Section 11.8 states:
The following emission rates and/or standards for each air contaminant emitted from any equipment, facility or air contaminant control device shall be specified in each permit issued pursuant to this regulation:

a. *The rate and/or standard established and/or relied upon in the State Implementation Plan (SIP) to include the State of Delaware "**Regulations Governing the Control of Air Pollution**" and regulations promulgated pursuant to Section 111 and Section 112 of the Clean Air Act (CAA); and*
b. *The rate that was shown under Section 11.6 as not interfering with the attainment and maintenance of any National and State ambient air quality standard, and not endangering the health, safety, and welfare of the people of the State of Delaware; or*
c. *The rate requested by the applicant. In no case shall this rate be greater than the potential to emit of the equipment, facility, or air contaminant control device; and in no case shall this rate be less stringent than the rate specified in Section 11.8(a) and (b) of this regulation.*

This regulation is applicable to the Boilers since this new equipment will emit air contaminants. Table 6 shows the Boilers' potential to emit as detailed in the application.

Table 6

	Hourly Emissions (each boiler, lbs.)	Yearly Emissions (each boiler, tons)	Combined Emissions (tons per year)
SO_2	4.8[51]	21.2	42.3
NOx	5.6	24.6	49.1
TSP	1.4	6.1	12.1
H_2SO_4	0.1	0.4	0.8
PM_{10}	1.5	6.4	12.9
CO	15.3	66.9	133.9
VOC	1.0	4.4	8.8
Lead	Neg.	4.0E-04	8.0E-04

The two boilers are subject to the permitting requirements of this regulation because it involves the construction and operation of equipment that will emit more than ten (10) pounds per day of nitrogen oxides (NOx), volatile organic compounds (VOCs), carbon monoxide (CO), particulate matter (PM), and sulfur oxides (SOx).

Premcor has not provided a steam balance for the plant. Although the application states the primary purpose[52] of the 2 package boilers is to provide steam for the regeneration of the amine

[51] The application lists expected SO_2 "emissions with air pollution control device (APCD)" at 4.8 lbs/hr ands SO_2 emissions "without APCD" at 9.7 lbs/hr. The application does not reference what that APCD will be or how it will reduce the SO_2 emissions.

[52] Although they will be constructed to provide the steam needed for the WGS systems, the boilers will also be tied into the refinery steam header. The application suggests this approach has been proposed to ensure appropriate redundancy. Premcor is constructing two package boilers rather than one large field erected boiler for several reasons. First, two boilers are best suited to the operational and turndown requirements of the WGS. Essentially, there is a boiler for the FCU WGS and one for the FCCU WGS. When one of the scrubbers is offline, its corresponding boiler can be removed from service. The second reason in the application is for reliability. This minimizes the times when the WGS steam will be needed from other sources in the refinery and reduces the burden on the existing steam supply. Finally, the application indicates, constructing the two boilers is more practical considering the costs and schedule. Two

absorbent used in the wet gas scrubbers, AQM is not convinced this is the only use for these units. AQM's concerns are as follows:

First, the preliminary design and process flow designs for the package boilers indicate each will supply 150,000 pounds of steam at 175 psig. While AQM does not dispute this system's steam requirement, AQM notes that it does not seem consistent with the steam usage requirements at other similar applications of this technology. For instance, AQM's records indicate a guaranteed steam consumption of 20 kg/kg SO_2 at a chemical plant in Belgium[53] where flue gas is desulfurized. This plant's actual performance showed steam consumption of 11 kg/kg SO_2 and is expected to be optimized to 7 kg/kg SO_2 after appropriate start up/commissioning lessons are implemented. Based on the material balance in the PCUP application, this translates into roughly one steam generating unit as being sufficient when fired at 150 mmBTU for both units (the FCU and the FCCU wet gas scrubbers).

Second, because the package boilers will deliver steam to the common refinery 175 psig steam header, there is no practical way of ensuring that steam generated by the package boilers is not used elsewhere in the refinery and thus debottlenecking other steam consuming unit operations that would otherwise be subject to regulatory review.

Nitrogen Oxides (NOx):

The application states NOx will be produced at a rate of 0.026 pounds per million BTU based upon design specifications. These specifications have not been provided to the Department.

Sulfur Dioxide (SO_2):

SO_2 emissions are directly proportional to the sourness (i.e., the H_2S content) of the gas. The refinery fuel gas the facility produces is regulated by 40 CFR Part 60 Subpart J Standards of Performance for Petroleum Refineries and must maintain compliance with the 162 ppm sulfur content in refinery gas requirement. Based on this content, the boilers' SO_2 emission factor is listed as 0.022 lb/mmBTU.

Total Suspended Particulates (TSP):

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package boilers can be fabricated, installed, and commissioned more quickly than a single field erected unit.

[53] "Cansolv Sulfur Dioxide Scrubbing System", Valerie Leveille, Cansolv Technologies

The boilers' TSP emission factor of 0.0064 lb/mmBTU is based upon Table 1.4-6[54] from AP-42 (July 1998 edition) and a high heating value of 1185 BTU/scf of refinery fuel gas.

Sulfuric Acid (H_2SO_4):

The sulfuric acid emission factor is 0.00041 lb/mmBTU and based upon the SO_2 emission factor of 0.022 lb/mmBTU. The rate is determined as follows:

$$0.022\frac{lb}{mmBTU} \times \frac{98 lbH2SO4}{64 lbSO2} \times 1.2\% = 0.00041\frac{lb}{mmBTU}$$

1.2% is the assumed SO_2 oxidation fraction.

Carbon Monoxide (CO):

Good engineering practice has established an emission rate of 400 ppm of Carbon Monoxide as a desirable rate that can be achieved through regular boiler tune ups.

The application proposes an emission rate of 0.071 lb/mmBTU from AP-42, Table 1.4-1 (large wall fired boilers). This rate is equivalent to 84 ppm. AQM finds this rate acceptable for the boilers.

$$0.071\frac{lbCO}{mmBTU} \times \frac{\min}{41{,}674 scf} \times \frac{hr}{60\min} \times \frac{385.3 scfCO}{28 lbCO} \times \frac{215.6 mmBTU}{hr} = 84 x 10^{-6}$$

Volatile Organic Compounds (VOC):

The emission factor of 0.0046 lb/mmBTU is from AP-42, Table 1.4-2.

Lead (Pb):

The emission factor of 4.2E-07 lb/mmBTU is from AP-42, Table 1.4-2.

Regulation No. 3 – Ambient Air Quality Standards:

[54] From Chapter 1.4 "External Combustion Equipment firing Natural Gas".

This regulation is applicable to all affected emissions units in the refinery. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 4 – Particulate Emissions from Fuel Burning Equipment:

Section 2.1 of this regulation states:
No person shall cause or allow the emission of particulate matter in excess of 0.3 pound per million BTU heat input, maximum 2-hour average, from any fuel burning device.

Compliance Methodology:

The boilers' TSP emission factor of 0.0064 lb/mmBTU is based upon Table 1.4-6[55] from AP-42 (July 1998 edition) and a high heating value of 1185 BTU/scf of refinery fuel gas. This amount is well below the regulatory limit. Gaseous fuels, by nature produce insignificant quantities of particulate matter.

Compliance will be demonstrated through proper operation and maintenance of these units.

Regulation No. 6– Particulate Emissions from Construction and Materials Handling:

This regulation is applicable to all affected emissions units in the refinery where construction activity will take place. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 8- Sulfur Dioxide Emissions from Fuel Burning Equipment:

Section 1.1 of this regulation states:
The emission of SO_2 from fuel burning equipment shall be controlled to a limit that shall meet the ambient air quality requirements.

Compliance Methodology:
Compliance with this and Regulation No. 3 is addressed under Facility Wide Regulations.

Section 2.1 of this regulation states:
No person shall use any fuel having a sulfur content greater than one (1.0) percent by weight in any fuel burning equipment in New Castle County.

[55] From Chapter 1.4 "External Combustion Equipment firing Natural Gas".

The sulfur content of refinery fuel gas (RFG) can not exceed 162 ppm as required by NSPS Subpart J. This equates to a sulfur content of 0.03%, well below the limit.

Compliance Methodology:

Compliance with this regulation will be demonstrated by the refinery gas plant's (Unit 24) compliance with NSPS Subpart J.

Regulation No. 12- Control of Nitrogen Oxide Emissions

Section 3.2(b) of this regulation states:
Reasonably Available Control Technology (RACT) shall be installed with the goal of achieving the presumptive emission limits as set forth in Table I. RACT for this category of equipment will consist of combustion modification technology including either:

i. low NOx burner technology with low excess air and including Over Fire Air if technology is feasible; or
ii. flue gas recirculation with low excess air.

Table I limits the emission rate for face and tangential boilers firing gas to 0.20 lb NOx/mmBTU heat input on a rolling 24 hour rolling average. As discussed below, AQM is seeking a NOx emission rate of 0.007 lb/mmBTU, per Regulation No. 25.

Compliance Methodology:

The application states NOx emissions will be controlled at a rate of 0.026 lb/mmBTU but gives no details on how this will be achieved. During a a technical meeting[56] on August 5, 2004, Premcor staff informed AQM that the boilers will have Ultra Low NOx Burners (ULNB) and a Selective Catalytic Reduction system (SCR) to control NOx. Compliance will be achieved through the testing and monitoring requirements.

Monitoring/Testing:

Pursuant to Section 3.2(d)(ii)(A), the Company shall install a CEMS to monitor NOx emissions. This is also a requirement in 40 CFR Part 60 Subpart Db described below.

[56] Email dated August 8, 2004 from Ravi Rangan to Ali Mirzakhalili: "Premcor PCUP Technical Meeting No. 5 dated August 6, 2004.

Regulation No. 14 – Visible Emissions:

Section 2.1 of this regulation states:
No person shall cause or allow the emission of visible air contaminants and/or smoke from a stationary or mobile source, the shade or appearance of which is greater than twenty (20%) percent opacity for an aggregate of more than three (3) minutes in any one (1) hour or more than fifteen (15) minutes in any twenty-four (24) hour period.

Compliance Methodology:

The Company shall maintain a log of daily quantitative observations using Reference Method 9 in Appendix "A" of 40 CFR part 60. In the event visible emissions are observed by reference Method 22, the Company shall conduct a visible emissions evaluation using the procedures described in Regulation 20, section 1.5 (c). At all other times, compliance shall be based on the proper operation of the emissions unit and record keeping.

Monitoring/Testing:

Conduct visual observations at fifteen-second intervals for a period of not less than one hour except that the observations may be discontinued whenever a violation of the standard is recorded. The additional procedures, qualification and testing used for visually determining the opacity shall be those specified in Section 2 and 3 (except for Section 2.5 and the second sentence of Section 2.4) of reference Method 9 set forth in Appendix A, 40 CFR Part 60, revised July 1, 1982.

Recordkeeping:

Observation records shall be maintained on site. Records of all maintenance performed on applicable units shall be maintained.

Reporting:

The Company shall submit quarterly reports indicating the duration and magnitude of all periods of excess opacity.

Regulation No. 17 – Source Monitoring, Recordkeeping and Reporting:

Section 2.1 of this regulation states:

Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, install, maintain, and use emission monitoring devices, keep records, and make periodic reports to the Department on the nature and amount of emissions from such source. The Department shall make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
Upon written request of the Department, an owner or operator of an air contaminant source shall, at his expense, sample the emissions of, or fuel used by, that source, maintain records and submit reports to the Department on the results of such sampling. The Department may make such data available to the public as reported and as correlated with any applicable emission standards or limitations.

Section 2.2 of this regulation states:
The Department may conduct tests of emissions from or fuel used by any air contaminant source. Upon written request of the Department, the owner or operator of the air contaminant source shall provide necessary holes in stacks or ducts, and such other safe and proper sampling and testing facilities, exclusive of instruments and sampling devices, if any are necessary, for proper determinations of the emission of air contaminants. The Department shall have access to and use of monitoring, record-keeping and reporting required by Federal Regulations relating to emissions of air contaminants. The Department may make such data available to the public as reported or received and as correlated with any applicable emissions standards or limitations.

Compliance Methodology:

The Company shall install, maintain and use a NOx continuous emission monitoring system to determine the NOx emission rate as required by 40 CFR Part 60, Subpart Db.

Monitoring/Testing, Recordkeeping and Reporting:

The Company shall conduct an initial NOx and CO performance tests for each unit. AQM reserves the right require future performance tests.

Regulation No. 19– Control of Odorous Air Contaminants

This regulation is applicable to all affected emissions units in the refinery. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

Regulation No. 20 & 40 CFR 60, Subpart J – Standards of Performance for Petroleum Refineries

Section 11 adopts 40 CFR Part 60 Subpart J by reference. §60.104(a) is an applicable requirement for the boilers. This requirement restricts the H_2S content in the RFG to less than 162 ppmvd. The H_2S concentration in the RFG is already monitored by CEMS within the refinery. Therefore, no new additional discussion is presented here.

Regulation No. 20- New Source Performance Standards

Section 26 adopts 40 CFR Part 60 Subpart Db by reference. This regulation is applicable to equipment that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 mmBTU/hr (29 MW). (*See 40 CFR Part 60 Subpart Db below*)

Regulation No. 24 – Control of Volatile Organic Compound Emissions

Fuel combustion units are exempted from this regulation by Section 50(a)(4).

Regulation No. 25- Requirements for Preconstruction Review

This regulation is applicable because the combined NOx emissions from the boilers will exceed the 25 ton per year threshold. Because the application made no mention of its applicability or how compliance will be achieved, AQM explored the following three options to develop a permitting strategy for these boilers:

Option 1: AQM will determine the technology that will achieve the lowest achievable emission rate (LAER) and require the Company to install that technology and meet that rate; or

Option 2: Permit the construction of both units, but restrict operation of the units to a level equivalent to the operation of only one unit because a single unit does not exceed the 25 tons per year threshold (24.6 tons), thus making this a Synthetic Minor permitting exercise; or

Option 3: AQM will research current LAER applicability determinations made by sister regulatory agencies for similar applications and require the Company to meet that rate.

Each option is discussed below in greater detail.

Option 1 - Determine LAER Technology

Requirements pertaining to Regulation No. 25, Section 2 - EOP require the Company to:

- Demonstrate that the source is controlled by the application of the lowest achievable emission rate (LAER) control technology.
- Demonstrate that all existing sources in the State owned or controlled by the owner of the proposed new source are in compliance with the applicable local, State and federal regulations or are in compliance with a consent order specifying a schedule and timetable for compliance.
- Demonstrate that the new source satisfies the offset requirements (total actual emissions reductions to total allowable increased emissions) of 1.3:1 for NOx.
- Demonstrate that all offsets will be federally enforceable at the time of application to construct and will be in effect by the time the new source commences operation.
- Include, in the Regulation No. 2 construction permit application, an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.
- Provide opportunities for public participation for the construction permit pursuant to Regulation No. 2, Section 12.3 or 12.4 and 12.5.

LAER Technology Analysis

In order to lend perspective to the forthcoming discussion on the application of LAER to the boilers, it is necessary to review the meaning of LAER. Regulation No. 1 defines LAER as follows: "The rate of emissions based on the following, whichever is most stringent:

- The most stringent emission limitation which is contained in the implementation plan of any state for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitation are not achievable; or

- The most stringent emission limitation which is achieved in practice by such class or category of source. This limitation when applied to a modification means the lowest achievable emission rate for the new or modified emissions unit within a stationary source. In no event shall the application of the term permit a proposed new or

> modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source performance standard.

AQM did not select this option because of the aggressive timeframe required for this permitting exercise. The Consent Decree requires the permits to be issued within eight (8) months of the application's submittal. With the applications submitted March 31, permits are required to be issued by November 30, 2004. AQM is unable to make a suitable determination within this limited timeframe.

Option 2 - Permit Two Boilers as a Synthetic Minor

Option #2 is to permit construction of both units with restrictions so that the 25 ton per year threshold would not be exceeded and trigger the permitting requirements of this regulation. However, this option would necessitate permitting the package boilers as a Synthetic Minor. AQM would be willing to explore this option but Premcor has not supplemented its application with information that would help AQM pursuer this approach. This option entails additional timelines that in turn, would not allow the package boiler permitting exercise to be in concert with the rest of the Pollution Control Upgrade Package.

Option 3 - Apply Current LAER to the Boilers:

The EPA's RACT/BACT/LAER Clearinghouse makes no official LAER determination for industrial-size boilers/furnaces with a heat input rating between 100 and 250 mmBTU/hr firing anything but natural gas.

A review of the database for other fuels, including refinery fuel gas, was completed. The lowest emission rate found was 0.035 lb/mmBTU at the delayed coker heater at the United Refinery in Pennsylvania. Low NOx burners were installed to achieve this rate.

Next, the state of California's Air Resources Board website was reviewed along with websites from some of the state's air quality management districts (AQMD). Each website contained databases listing BACT (best available control technology) determinations (California's LAER equivalent) and other information. For boilers and heaters firing refinery fuel gas, AQM's research determined:

- The Cheveron Products Co. in El Sugundo has a 653 mmBTU/hr furnace fired on refinery gas with a permitted emission rate of 5 ppmvd @ 3% O_2, 3-hour rolling average. The reformer furnace is located at the Steam Naphtha Reformer plant and is used for hydrogen production. The unit employs a Selective Catalytic Reduction system (SCR) to

achieve this rate. The unit also has emission limits for CO and NH_3 of 25 and 10 ppmvd @ 3% O_2, 3-hour average, respectively.

- A construction permit was issued for a reformer heater at Air Products and Chemical Inc. with an emission limit of 5 ppm NOx. SCR is used to control NOx emissions.

- The San Joaquin Valley Air Pollution Control District's Rule 4306 for Boilers, Steam Generators, and Process Heaters (Sept. 2003 edition) requires an emission rate of 5 ppmvd (0.0062 lb/mmBTU) for all new or modified boilers greater than 110 mmBTU/hr heat input operating on gaseous fuel. San Joaquin also limits CO emissions to 400 ppmv.

Other findings include:

- The South Coast AQMD permitted a heater at a Tosco refinery at 7 ppmvd @ 3% O_2. The heater is rated at 460 mmBTU/hr and uses SCR to the NOx emissions. CO is limited to 100 ppmvd @ 3% O_2;

- The Bay Area AQMD's BACT requires boilers with a heat input rating greater than 50 mmBTU/hr to achieve a NOx emission rate of 9 ppmvd @ 3% O_2. CO is limited to 50 ppmvd @ 3% O_2; and

- The San Joaquin AQMD has determined it is technically feasible to control NOx to a rate of 1.7 ppmvd (0.0021 lb/mmBTU) using SCR and a Low NOx burner system. This is not yet a regulatory or permitted limit.

The following table summarizes Best Available Control Technology (BACT) regulatory emission rates in the State of California for heaters and boilers:

Emission Rate (ppmvd @ 3% O_2)	Equivalent Emission Rate (lb/mmBTU)	BACT Emission Limit	Notes
5	0.007	San Joaquin Valley AQMD	For refinery units greater than 110 mmBTU/hr operating on gaseous fuel
7	0.010	South Coast AQMD	For units employing SCR control technology
9	0.0108	South Coast AQMD	For units employing Ultra Low NOx Burner technology
9	0.0108	Bay Area AQMD	For any boiler greater than 50 mmBTU/hr firing any fuel

9	0.0108	State of Texas	For boilers greater than 40 mmBTU/hr.

Research shows the following companies have met their respective permitted emission rates:

Permitted Emission Rate (ppmvd @ 3% O_2)	Equivalent Emission Rate (lb/mmBTU)	Company	Rating, Control
5	0.007	Cheveron Products, El Segundo, CA	653 mmBTU/hr Furnace, Low NOx Burners, SCR
5	0.007	Cheveron Products, El Segundo, CA	780 mmBTU/hr Furnace, LNB and SCR
5	0.007	Air Products & Chemicals Wilmington, CA	785 mmBTU/hr Heater, LNB and SCR
7	0.010	Tosco Wilmington, CA	460 mmBTU/hr Heater, Low NOx Burners, SCR

The 5 ppm emission rate is equivalent to 0.007 lb of NOx per million BTU heat input for Premcor's proposed boilers.

$$5x10^{-6} \times 41{,}674 \frac{scf}{\min} \times 60 \frac{\min}{hr} \times \frac{46lb}{385.3scf} \times \frac{hr}{215.6mmBTU} = 0.007 \frac{lb}{mmBTU}$$

The table below compares the emissions that will result from the rate given in Premcor's application to emissions based upon the 5 ppm concentration.

	Emission Rate (lb/mmBTU)	Emission Rate (ppm)	Hourly Emissions	Annual Emissions (per boiler)	Annual Emissions (both boilers)
Application	0.026	19	5.6 lbs	24.6 tons	49.2 tons
AQM's Proposed Rate	0.007	5	1.5 lbs	6.6 tons	13.2 tons

It is recommended that AQM consider the State of California's BACT determinations to be "LAER" for the purposes of this operation and limit the boilers' NOx emissions to 0.007 lb/mmBTU (5 ppmvd). This emission rate reduces the boilers' potential to emit from 49.2 tons per year to 13.2 tons per year.

Regulation No. 30– Title V State Operating Permit Program

This regulation is applicable to all affected emissions units in the refinery where construction activity will take place. Therefore, its applicability is covered under the heading "Facility Wide Applicable Requirements" in this memorandum.

40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The provisions of this subpart apply to each boiler because they will commence construction after June 19, 1984, and each has a rated heat input capacity of greater than 100 million BTU per hour.

The boilers also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; Sec. 60.104) and they are subject to the nitrogen oxides standards and particulate matter standard under this subpart and the sulfur dioxide standards under subpart J (Sec. 60.104). The particulate matter standards of 60.43b(f) do not apply to these units because they only combust refinery fuel gas.

Standard for Particulate Matter:

The boilers shall not cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average). This is also required by Regulation No. 14.

Standards for NOx Emissions:

On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, Premcor shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 0.20 lb/mmBTU heat input.

The nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

Compliance with the emission limits under this section is determined on a 30-day rolling average basis.

Compliance Methodology:

The Company shall demonstrate compliance with the NOx emission limitation through performance testing within 180 days of initial startup.

Monitoring & Testing Requirements:

The Company shall demonstrate compliance with the NOx emission limits with the monitoring and testing requirements in §§60.46b(e), 60.48b(b)(1), 60.48b(b)(1), 60.48b(c)-(f) through the following requirements:

(a) Compliance shall be based on the CEMS. The CEMS shall be installed and certified by satisfying the requirements of Performance Specifications N0. 2 in Appendix "B" of 40 CFR Part 60. The QA/QC procedures for the CEMS shall be established in accordance with the procedures in Appendix "F" of 40 CFR Part 60.

(b) Install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(c) The continuous monitoring systems shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under Sec. 60.13(h) shall be expressed in lb/million Btu heat input and shall be used to calculate the average emission rates under Sec. 60.44b. The 1-hour averages shall be calculated using the data points required under Sec. 60.13(b). At least 2 data points must be used to calculate each 1-hour average.

(e) The procedures under Sec. 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. The span value is 500 ppm.

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

Reporting and Recordkeeping Requirements

The following recordkeeping and reporting requirements are applicable:

(a) The Company shall submit the performance test data from the initial performance test and the performance evaluation of the CEMS.

(b) The Company shall record and maintain records of the amounts of each fuel combusted during each day and calculate the refinery fuel gas's annual capacity factor for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(c) The Company shall maintain records of the following information for each steam generating unit operating day:
   (1) Calendar date.
   (2) The average hourly NOx emission rates (expressed as NO_2) (lb/million BTU heat input) measured.
   (3) The 24-hour average NOx emission rates (lb/million Btu heat input) calculated at the end of each 24-hour period.
   (4) Identification of the periods when the calculated 24-hour average NOx emission rates are in excess of the standard, with the reasons for such excess emissions as well as a description of corrective actions taken.
   (5) Identification of the periods for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.
   (6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.
   (7) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.
   (8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
   (9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.
   (10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(d). The Company is required to submit excess emission reports for any excess emissions which occurred during the reporting period.

(e) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 5 years following the date of such record.

(f) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Department and shall be postmarked by the 30th day following the end of the reporting period.

Facility Wide Requirements:

Regulation No. 3:

Section 2.1 of this regulation states:
No person shall cause the Air Quality Standards specified in this Regulation to be exceeded.

Compliance Method:[57]

Premcor has conducted a modeling analysis for normal operation using the EPA approved Industrial Source Complex Short Term (ISCST3 version 02035) model and 5 years of representative meteorological data to show no adverse impacts to ambient air quality standards.

Regulation No. 14:

The Company shall not cause or allow the emission of visible air contaminants and/or smoke from any emission unit, the shade or appearance of which is greater than twenty (20) percent opacity for an aggregate of more than three (3) minutes in any one (1) hour or more than fifteen (15) minutes in any twenty-four (24) hour period.

Compliance Method:
Compliance with the emission standard of this condition shall be demonstrated in accordance with Subsection 1.5(c) of Regulation No. 20 and the recordkeeping requirements of this condition

Monitoring/Testing:

[57] See also discussion under applicability of Regulation 3 to atypical operations of the FCU and for the ongoing violations of the Delaware Secondary 24 hour Ambient air Quality Standard for Total Suspended Particulate Matter.

In accordance with Regulation No. 20 Section 1.5, conduct visual observations at fifteen second intervals for a period of not less than one hour except that the observations may be discontinued whenever a violation of the standard is recorded. The additional procedures, qualification and testing to be used for visually determining the opacity shall be those specified in Section 2 and 3 (except for Section 2.5 and the second sentence of Section 2.4) of reference Method 9 set forth in Appendix A, 40 CFR Part 60 revised July 1, 1982.

- The Company shall conduct weekly qualitative plant-wide stack observations to determine the presence of any visible emissions.
- If visible emissions are observed, the Company shall take corrective actions and/or determine compliance by conducting a visible observation in accordance with the above paragraph.

If no visible emissions are observed or are within permitted limits, no further action is required.

Record Keeping:
Observation records shall be maintained on site.

Reporting:

The Company shall report all exceedances of the standard quarterly

Regulation No. 19:

The Company shall not cause or allow the emission of an odorous air contaminant such as to cause a condition of air pollution.

Compliance Method:
Compliance with the emission standard of this condition shall be demonstrated in accordance with the monitoring/testing and record keeping requirements of this condition.

Monitoring/Testing:
Includes but is not limited to scentometer tests, air quality monitoring, and affidavits from affected citizens and investigators.

Recordkeeping:
Records of all monitoring/testing shall be maintained on site.

Reporting:

The Company shall provide reasonable notice to the Department of the possibility of odors being encountered offsite during process upsets.

Regulation No. 24: **Handling, Storage and Disposal of VOCs**

Work Practice Standards

A. The Company shall not cause, allow, or permit the disposal of more than eleven (11) pounds of a Volatile Organic Compound (VOC), or of any materials containing more than eleven (11) pounds of any VOCs, in any one (1) day, in a manner that would permit the evaporation of VOC into the ambient air. This includes but is not limited to the disposal of VOC from any VOC control devices. This provision does not apply to:
   - Any VOC or material containing VOC emitted from a regulated entity that is subject to a VOC standard under Regulation No. 24.
   - Any VOC or material containing VOCs used during process maintenance turnarounds for cleaning purposes, provided that the provisions of paragraph (B), (C), and (D) of this condition are followed.
   - Waste paint (sludge) handling systems, water treatment systems, and other similar operations at coating facilities using complying coatings.

B. No owner or operator of a facility subject to this regulation shall use open containers for the storage or disposal of cloth or paper impregnated with VOCs that are used for surface reparation, cleanup, or coating removal. Containers for the storage or disposal of cloth or paper impregnated with VOCs shall be kept closed, except when adding or removing material.

C. No owner or operator of a facility subject to this regulation shall store in open containers spent or fresh VOC to be used for surface preparation, cleanup or coating removal. Containers for the storage of spent or fresh VOCs shall be kept closed, except when adding or removing material.

D. No owner or operator shall use VOC for the cleanup of spray equipment unless equipment is used to collect the cleaning compounds and to minimize their evaporation to the atmosphere.

Compliance Method:
Compliance shall be demonstrated by adherence with the VOC handling work practices by providing appropriate training and posting of instructions, and record keeping for storage, use and disposal of VOCs.

Monitoring/Testing:
The Company shall monitor employee training records on an annual basis and update records as needed.

Recordkeeping:
The Company shall keep a record of postings, and employee training related to these work practice standards and handling, storage, and disposal of VOCs.

Reporting/Certification:
The Company shall indicate the compliance status with this regulation in the form of a certification statement in each quarterly report.

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